

California Climate Action Registry

Electric Power Generators,
Utilities, and Natural Gas Entities

Draft Appendix to the *General Reporting Protocol*

Draft Version for Public Comment

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Appendix X to the General Reporting Protocol: Power/Utility Reporting Protocol

Reporting Entity-Wide Greenhouse Gas Emissions Produced by Electric Power Generators, Electric Utilities and Natural Gas Entities

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Acronyms and Abbreviations

API	American Petroleum Institute
C	carbon
CARROT	Climate Action Registry Reporting Online Tool
CEC	California Energy Commission
CEM	Continuous Emissions Monitor
CH ₄	methane
CO ₂	carbon dioxide
DOE	U.S. Department of Energy
eGRID	Emissions & Generation Resource Integrated Database
EIA	Energy Information Administration (U.S. DOE)
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GHGs	greenhouse gases
GRP	General Reporting Protocol
GWP	Global Warming Potential
HFC	hydrofluorocarbon
kWh	kilowatt-hour
Lb.	pound
MMBtu	million British thermal units
MWh	Megawatt-hour
N ₂ O	nitrous oxide
NERC	North American Electric Reliability Council
PFC	perfluorocarbon
PUP	Power/Utility Protocol
Registry	The California Climate Action Registry
SEC	Securities & Exchange Commission
SF ₆	sulfur hexafluoride
T&D	transmission and distribution
WRI	World Resources Institute

Key Power/Utility Protocol Terms

Term	Definition	Source
Boiler	A device for generating steam for power, processing, or heating purposes or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes in the boiler shell. This fluid is delivered to an end-use at a desired pressure, temperature, and quality.	Power Marketing Association (PMA)
Bulk Electric System	A term commonly applied to the portion of an electric utility system that encompasses the electrical generation resources and bulk transmission system.	North American Electric Reliability Council (NERC)
Bulk Transmission	A functional or voltage classification relating to the higher voltage portion of the transmission system.	NERC
Capacity	The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment.	NERC
Capacity Factor	The ratio of the total energy generated by a generating unit for a specified period to the maximum possible energy it could have generated if operated at the maximum capacity rating for the same specified period, expressed as a percent.	NERC
Cogeneration	Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.	NERC
Combined Cycle	An electric generating technology in which electricity and process steam is produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.	NERC
Continuous Emission Monitoring System	CEM is the continuous measurement of pollutants emitted into the atmosphere in exhaust gases from combustion or industrial processes. CEM systems include: <ul style="list-style-type: none"> An SO₂ pollutant concentration monitor. A NO_x pollutant concentration monitor. A volumetric flow monitor. An opacity monitor. A diluent gas (O₂ or CO₂) monitor. A computer-based data acquisition and handling system (DAHS) for recording and performing calculations with the data. 	U.S. Environmental Protection Agency (EPA)
Demand	The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. Demand should not be confused with Load.	NERC
Demand-Side Management	The term for all activities or programs undertaken by an electric system or its customers to influence the amount or timing of electricity use.	NERC
<i>De minimis</i>	A quantity of GHG emissions from one or more sources, for one or more gases, which, when summed equal less than 5% of an organization's total emissions.	
Direct monitoring	Direct monitoring of exhaust stream contents in the form of continuous emissions monitoring (CEM) or periodic sampling.	World Resources Institute (WRI)

Term	Definition	Source
Distribution System	The low voltage system of power lines, poles, substations and transformers, directly connected to homes and businesses. Your Distribution Company is the electric utility that delivers electricity to your home or business over these wires. The utility will read your meter, maintain local wires and poles and restore your power in the event of an outage.	Center for Resource Solutions (CRS)
Electric Plant (Physical)	A facility containing prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or fission energy into electric energy.	PMA
Electric System Losses	Total electric energy losses in the electric system. The losses consist of transmission, transformation, and distribution losses between supply sources and delivery points. Electric energy is lost primarily due to heating of transmission and distribution elements.	NERC
Electric Utility	A corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation, transmission, distribution, or sale of electric energy primarily for use by the public and is defined as a utility under the statutes and rules by which it is regulated. Types of Electric Utilities include investor-owned, cooperatively owned, and government-owned (federal agency, crown corporation, state, provincials, municipals, and public power districts).	NERC
Electrical Energy	The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).	NERC
Federal Energy Regulatory Commission (FERC)	A quasi-independent regulatory agency within the Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification.	PMA
Fuel Totalizer	A meter that sums the volume or mass of fuel used (rather than the flow of fuel).	
Fugitive Emissions	Unintended leaks of gas from the processing, storage, transmission, and/or transportation of fossil fuels.	U.S. Department of Energy (DOE)
Generation (Electricity)	The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatthours (kWh) or megawatthours (MWh).	NERC
Geothermal Plant	A plant with steam turbines powered by either steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the earth. The energy is extracted by drilling and/or pumping.	PMA
Gross Generation	The electrical output at the terminals of the generator, usually expressed in megawatts (MW).	NERC
Heating value	The amount of energy released when a fuel is burned completely. Care must be taken not to confuse higher heating values (HHVs), used in the US and Canada, and lower heating values, used in all other countries.	WRI GHG Protocol
Independent Power Producers (IPP)	As used in NERC reference documents and reports, any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators who sell electricity.	NERC

Term	Definition	Source
Kilowatt-Hour	The standard unit of measure for electricity. One kilowatt-hour is equal to 1,000 watt-hours. The total number of kilowatt-hours charged to your bill is determined by your electricity use. For example, if you used a 100-watt light bulb for 10 hours, you would be billed for one kilowatt-hour (100 watts x 10 hours= 1,000 watt-hours). The average home in the United States uses 750 kWh/ month.	
Liquefied Natural Gas	Natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.	U.S. DOE Energy Information Administration (EIA) ¹
Load	An end-use device or customer that receives power from the electric system. Load should not be confused with Demand, which is the measure of power that a load receives or requires. See Demand.	NERC
Mains Megawatt-Hour Metering	Physical system through which fuels are transported. One thousand kilowatt-hours or 1 million watt-hours. The methods of applying devices that measure and register the amount and direction of electrical quantities with respect to time.	NERC
Municipal Utility	A municipal utility is a non-profit utility that is owned and operated by the community it serves. Whether or not a municipal utility is open to customer choice and competition is decided by the municipality's public officials.	
Net Capacity	The maximum capacity (or effective rating), modified for ambient limitations, that a generating unit, power plant, or electric system can sustain over a specified period, less the capacity used to supply the demand of station service or auxiliary needs.	NERC
Net Energy for Load	The electrical energy requirements of an electric system, defined as system net generation, plus energy received from others, less energy delivered to others through interchange. It includes system losses but excludes energy required for storage at energy storage facilities.	NERC
Net Generation	Gross generation minus station service or unit service power requirements, usually expressed in megawatts (MW).	NERC
North American Electric Reliability Council (NERC)	A not-for-profit company formed by the electric utility industry in 1968 to promote the reliability of the electricity supply in North America. NERC consists of nine Regional Reliability Councils and one Affiliate whose members account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The members of these Councils are from all segments of the electricity supply industry — investor-owned, federal, rural electric cooperative, state/municipal, and provincial utilities, independent power producers, and power marketers. The NERC Regions are: East Central Area Reliability Coordination Agreement (ECAR); Electric Reliability Council of Texas (ERCOT); Mid- Atlantic Area Council (MAAC); Mid-America Interconnected Network (MAIN); Mid-Continent Area Power Pool (MAPP); Northeast Power Coordinating Council (NPCC); Southeastern Electric Reliability Council (SERC); Southwest Power Pool (SPP); Western Systems Coordinating Council (WSCC); and Alaskan Systems Coordination Council (ASCC, Affiliate).	NERC

¹ EIA. http://www.eia.doe.gov/oil_gas/natural_gas/info_glance/natural_gas.html

Term	Definition	Source
Pipeline (Natural Gas)	A continuous pipe conduit, complete with such equipment as valves, compressor stations, communications systems, and meters, for transporting natural and/or supplemental gas from one point to another, usually from a point in or beyond the producing field or processing plant to another pipeline or to points of use.	EIA
Pipeline Fuel (Natural Gas)	Gas consumed in the operation of pipelines, primarily in compressors.	EIA
Power Pool	An association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies.	PMA
Qualifying Facility (QF)	A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by FERC pursuant to PURPA (See CFR, Title 18, Part 292).	PMA
Renewable Energy	Energy drawn from a source that is infinite or is replenished through natural processes. Such sources include the sun, wind, heat from the earth's core, biomass, and moving water.	California Energy Commission
Renewable Power	A power source other than a conventional power source, defined as power derived from nuclear energy or the operation of a hydropower facility greater than 30 megawatts or the combustion of fossil fuels, unless cogeneration technology...is employed in the production of such power.	California Energy Commission Renewable Energy Program: Overall Program Guidebook
Spot Purchases	A single shipment of fuel or volumes of fuel, purchased for immediate delivery or within one year. Spot purchases are often made by a user to fulfill a certain portion of energy requirements, to meet unanticipated energy needs, or to take advantage of low fuel prices.	PMA
Stocks	A supply of fuel accumulated for future use. This includes, but is not limited to, coal and fuel oil stocks at the plant site, in coal cars, tanks, or barges at the plant site, or at separate storage sites.	PMA
Storage	Energy transferred from one entity to another entity that has the ability to conserve the energy (i.e., stored as water in a reservoir, coal in a pile, etc.) with the intent that the energy will be returned at a time when such energy is more usable to the original supplying entity.	NERC
Substation	A facility for switching electrical elements, transforming voltage, regulating power, or metering.	NERC
Transformer	An electrical device for changing the voltage of alternating current.	PMA
Transmission (Electric)	An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.	NERC
Underground Gas Storage	The use of sub-surface facilities for storing gas that has been transferred from its original location. The facilities are usually hollowed-out salt domes, natural geological reservoirs (depleted oil or gas fields) or water-bearing sands topped by an impermeable cap rock (aquifer).	EIA
Wheeling Service	The movement of electricity from one system to another over transmission facilities of intervening systems. Wheeling service contracts can be established between two or more systems.	PMA
Wholesale Sales	Energy supplied to other electric utilities, cooperatives, municipals, and Federal and State electric agencies for resale to ultimate consumers.	PMA

Appendix X to the General Reporting Protocol: Power/Utility Reporting Protocol

Reporting Entity-Wide Greenhouse Gas Emissions Produced by Electric Power Generators, Electric Utilities and Natural Gas Entities

Chapter 1: Introduction

This document, the Power Generation/Electric Utility/Natural Gas Reporting Protocol (Power/Utility Protocol or PUP), is an appendix to the Registry's General Reporting Protocol (GRP). It provides reporting standards for how electric power generation and utility (natural gas transmission and distribution, and electricity transmission and distribution) entities must compile, report, and certify their **entity-wide GHG emissions** to submit their annual emissions inventory to the Registry.

The GRP provides the framework for businesses, government agencies, and non-profit organizations to participate in the California Climate Action Registry (the Registry). It presents the principles, approach, methodology, and procedures required for effective participation in the Registry. The GRP is designed to support the complete, transparent, and accurate reporting of an organization's greenhouse gas (GHG) emissions in a fashion that minimizes the reporting burden and maximizes the benefits associated with understanding the connection between fossil fuel consumption, energy production, and GHG emissions in a quantifiable manner.

The GRP guides participants through the Registry's reporting rules, emissions calculation methodologies, and the Climate Action Registry Reporting Online Tool (CARROT). By joining the Registry, participants agree to report their GHG emissions according to the guidelines in the GRP and its appendices.

Additional guidance is also provided for some industries that require additional clarification to report their California- or U.S. emissions in a comparable, consistent, and accurate manner. Thus, the Registry has developed the Power/Utility Protocol for companies that generate or transmit electricity and/or natural gas.

This document is divided into eleven chapters: Chapter 1 introduces the PUP, power/utility entity reporting, and discusses basic concepts and reporting criteria; Chapters 2-4 help power/utility entities establish their organizational, operational and geographic boundaries; Chapters 5-8 provide guidance to power/utility entities to quantify CA or U.S. emissions; Chapter 9 assists power/utility entities in quantifying and reporting industry-specific metrics; Chapter 10 provides guidance to power/utility entities on calculating de minimis emissions; and Chapter 11 provides guidance on optional reporting categories.

1.1 Eligibility

Use of the PUP is required for entities in the electric power and utility sectors when reporting entity-wide GHG emissions to the Registry. Power and utility entities are defined as those companies or facilities with the following codes in the North American Industry Classification System (NAICS)²:

2211 Electric Power Generation, Transmission and Distribution: This industry group is comprised of establishments primarily engaged in generating, transmitting, and/or distributing electric power. Establishments in this industry group may perform one or more of the following

² <http://www.census.gov/epcd/www/naics.html>

activities: (1) operate generation facilities that produce electric energy; (2) operate transmission systems that convey the electricity from the generation facility to the distribution system; and (3) operate distribution systems that convey electric power received from the generation facility or the transmission system to the final consumer.

22111 Electric Power Generation: This U.S. industry is comprised of establishments primarily engaged in operating electric power generation facilities. These facilities convert other forms of energy, such as water power (i.e., hydroelectric), fossil fuels, nuclear power, and solar power, into electrical energy. The establishments in this industry produce electric energy and provide electricity to transmission systems or to electric power distribution systems.

221111 Hydroelectric Power Generation: This U.S. industry is comprised of establishments primarily engaged in operating hydroelectric power generation facilities. These facilities use water power to drive a turbine and produce electric energy. The electric energy produced in these establishments is provided to electric power transmission systems or to electric power distribution systems.

221112 Fossil Fuel Electric Power Generation: This U.S. industry is comprised of establishments primarily engaged in operating fossil fuel powered electric power generation facilities. These facilities use fossil fuels, such as coal, oil, or gas, in internal combustion or combustion turbine conventional steam process to produce electric energy. The electric energy produced in these establishments are provided to electric power transmission systems or to electric power distribution systems.

221113 Nuclear Electric Power Generation: This U.S. industry is comprised of establishments primarily engaged in operating nuclear electric power generation facilities. These facilities use nuclear power to produce electric energy. The electric energy produced in these establishments is provided to electric power transmission systems or to electric power distribution systems.

221119 Other Electric Power Generation: This U.S. industry is comprised of establishments primarily engaged in operating electric power generation facilities (except hydroelectric, fossil fuel, nuclear). These facilities convert other forms of energy, such as solar, wind, or tidal power, into electrical energy. The electric energy produced in these establishments is provided to electric power transmission systems or to electric power distribution systems.

22112 Electric Power Transmission, Control, and Distribution: This industry is comprised of establishments primarily engaged in operating electric power transmission systems, controlling the transmission of electricity (i.e., regulating voltages), and/or distributing electricity. The transmission system includes lines and transformer stations. These establishments arrange, facilitate, or coordinate the transmission of electricity from the generating source to the distribution centers, other electric utilities, or final consumers. The distribution system consists of lines, poles, meters, and wiring that deliver the electricity to final consumers.

221121 Electric Bulk Power Transmission and Control: This U.S. industry is comprised of establishments primarily engaged in operating electric power transmission systems and/or controlling (i.e., regulating voltage) the transmission of electricity from the generating source to distribution centers or other electric utilities. The transmission system includes lines and transformer stations.

221122 Electric Power Distribution: This U.S. industry is comprised of electric power establishments primarily engaged in either (1) operating electric power distribution systems (consisting of lines, poles, meters, and wiring) or (2) operating as electric power brokers or agents that arrange the sale of electricity via power distribution systems operated by others.

221330 Steam and Air-Conditioning Supply: This industry is comprised of establishments primarily engaged in providing steam, heated air, or cooled air. The steam distribution may be through mains.

486210 Pipeline Transportation of Natural Gas: This industry is comprised of establishments primarily engaged in the pipeline transportation of natural gas from processing plants to local distribution systems.

221210 Natural Gas Distribution: This industry is comprised of: (1) establishments primarily engaged in operating gas distribution systems (e.g., mains, meters); (2) establishments known as gas marketers that buy gas from the well and sell it to a distribution system; (3) establishments known as gas brokers or agents that arrange the sale of gas over gas distribution systems operated by others; and (4) establishments primarily engaged in transmitting and distributing gas to final consumers.

1.2 Industries that Generate Power/Steam/Heat

Because numerous industrial sectors generate electricity, heat or steam for their own use and even for sale to outside entities, portions of the PUP should serve as a reference for quantifying emissions associated with these activities. For example, the section of the protocol that addresses direct combustion emissions associated with combined heat and power (CHP) operations may apply to numerous industries outside of the power utility industry that operate CHP.

Chapter 2: Defining Organizational Boundaries

This chapter discusses the options and requirements for determining your organizational boundaries. This includes guidance for what you must report in your GHG Emission Report based on your ownership of different facilities.

2.1 Types of Organizational Relationships in Power/Utility Sectors

The electric power and utility sectors have a multitude of ownership and management control arrangements for power generation facilities, transmission & distribution assets for electricity and natural gas, as well as for the commodities themselves (electricity, steam, heat, and natural gas). These ownership scenarios are listed below:

1. *Full ownership* – There is one single owner of the asset.
2. *Co-ownership* – There is more than one owner of the asset with varying degrees of ownership and operational control (ranging from 1% to 99%).
3. *Majority owner and operational control of the facility* – In some cases, the operator of the assets has control of the facility.
4. *Minority owner but operational control of the facility* – In some cases, the operator of an asset may not have majority ownership of the facility.
5. *Operator of the facility, but no ownership share* – In some cases, an entity has operational control without any ownership share.
6. *Leasing* – The asset is leased for a discrete duration of time, with operational control resting with the lease holder.
7. *Joint Power Agreement* – There is more than one public agency owner of the asset with varying degrees of ownership and operational control (ranging from 1% to 99%).

When determining your organizational boundaries, you may report using either management control and/or equity share. Because of the number of joint ownership arrangements common in power generation, it is *strongly recommended* that you calculate and report your GHG emissions using the equity share method. Whichever method you choose, you should report using the same method for every facility.

2.2 Equity Share

When reporting using equity share, you document only your company's economic interest in an operation. Your equity share will usually be the same as your ownership percentage.³

In the electric power and utility sector, joint ownership of assets is commonplace. To clarify ownership (rights) and responsibilities (obligations), companies involved in joint operations draw up contracts specifying the distribution of ownership between the parties. Where such arrangements exist, companies each report their emissions according to ownership arrangements described in the contracts.

2.3 Management Control

Under the management control approach, a company accounts for 100% of the GHG emissions

³ Language from the WRI/ WBCSD GHG Protocol Corporate Accounting and Reporting Standard (Revised Edition). <http://www.ghgprotocol.org/standard/index.htm>

from operations over which it has control. You should refer to the GRP if you have any questions as to whether or not you can establish management control.

If you choose to report using the management control method, you must also provide documentation from any partners with whom you share ownership in a facility acknowledging who will be reporting the emissions from that facility.

Table 2.1 demonstrates how emissions would be reported under the different ownership scenarios using equity share and/or management control approaches.

Table 2.1 Reporting Emissions Under Equity Share and Management Control Approaches

	Equity Share	Management Control
Full ownership	100%	100%
Co-ownership	1-99% (based on ownership share)	If >50%: 100% If < 50%: 0
Majority owner and operational control of the facility	>50% based on ownership share	100%
Minority owner but operational control of the facility	<50% based on ownership share	0
Operator of the facility, but no ownership share	0	100%
Leasing	100%	100%
Joint Power Agreement	Varies with ownership share	If operational control or ownership >50%: 100% emissions If no operational control or ownership <50%: 0

Chapter 3: Defining Operational Boundaries

This chapter provides guidance on determining which direct and indirect GHG emissions you must report to the Registry. You must report all significant CA or U.S. direct emissions.

3.1 Direct Emissions

Within the power/utility sectors, direct emissions come from:

- Stationary combustion from the onsite production of heat, steam, or electricity owned or controlled by your organization.
- Fugitive leaks or venting from operations owned or controlled by your organization.
- Processes such as emission control technologies and other activities that are owned or controlled by your organization.
- Mobile combustion from non-fixed sources that are owned or controlled by your organization.

This protocol provides guidance for you to calculate and report direct emissions from:

1. Stationary Combustion;
2. Fugitive Emissions from Electricity Transmissions & Distribution;
3. Fugitive Emissions from Natural Gas Transmission & Distribution; and
4. Process Emissions from SO₂ scrubbers.

Reporters should consult the General Reporting Protocol for guidance on calculating and reporting direct emissions from:

- **Mobile Combustion,**
- **Fugitive Emissions** from **Air Conditioning and Refrigeration Systems,** and
- **Fugitive Emissions** from **Fire Suppression Equipment.**

3.2 Indirect Emissions

Indirect emissions occur because of your actions, but are produced by sources owned or controlled by another entity. Indirect emissions come from:

1. Electricity, steam, heating and cooling purchased and consumed: These include emissions from the generation of purchased energy that is consumed in equipment owned or controlled by your organization.
2. Transmission and distribution losses:
 - a. the portion of electricity purchased by your organization that is consumed during its transmission and distribution to end-use customers through equipment and infrastructure that is owned or controlled by your organization (T&D loss), and
 - b. the portion of wheeled electricity that is consumed by transmission and distribution equipment and infrastructure that is owned or controlled by your organization, and
 - c. the portion of electricity consumed during its transmission and distribution to direct access customers.

Reporters should consult the General Reporting Protocol for guidance on calculating and reporting **indirect emissions** from:

- **Electricity Use,**
- **Co-generation,**
- **Imported Steam,** and
- **District Heating or Cooling.**

**Example 3-1. Defining Operational Boundaries:
An Electric Utility Company**

An electric utility company operating in California owns electric generating facilities, an electric transmission and distribution system, and a natural gas transmission and distribution system. The company generates electricity and also purchases it from other generators to supply customers in California. The company also has office buildings and a fleet of vehicles that it uses in its business operations.

This electric utility company's entity-wide GHG inventory will include the following direct and indirect emission sources:

- Stationary combustion
- Mobile combustion
- Process emissions
- Fugitive emissions
- Indirect emissions from energy imported and consumed at office buildings
- Indirect emissions from T&D losses

3.3 Establishing and Updating a Baseline

All Registry participants are encouraged to establish a baseline and adjust it over time. Chapter 3 of the GRP walks you through the options and process of selecting and establishing your baseline. For power/utility entities, the GRP provides all guidance needed to establish a baseline.

Chapter 4: Geographic Boundaries

This chapter discusses requirements for determining the geographic boundaries of your GHG Emission Report.

4.1 Determining Geographic Boundaries

You have the option of defining the reporting scope of your GHG inventory in two ways, either:

- 1) All GHG emissions in California (CA reporting), or
- 2) All GHG emissions in the US--separated into California and non-California inventories (U.S. reporting).

The Registry does not currently certify GHG emissions data from operations outside the U.S. However, you are encouraged to gather and retain this data for reporting to the Registry in subsequent years. You may currently report international emissions in the optional reporting section.

Emissions are calculated based on where the electricity you generate, transmit or distribute is consumed. If you own electricity generation inside and outside of California, your total reported direct emissions may change, depending on whether you report your U.S. or your CA emissions.

4.2 U.S. Reporting

To determine your U.S. direct emissions, follow the steps in Chapters 5-7 to calculate your total emissions from stationary combustion, power/utility processes, and fugitive sources for all facilities located in the U.S. Follow the steps in the GRP to calculate your total direct emissions from mobile combustion.

To determine your U.S. indirect emissions, follow the steps in Chapters 8 to calculate your total indirect emissions associated with energy purchased and consumed within the United States.

4.3 California Reporting

To determine your California direct emissions, you must calculate the emissions associated with electricity generated at any stationary combustion plant you own that is delivered to customers located inside the borders of the state of California. For generation stations physically located in the state, this includes all of the direct emissions associated with these facilities. You must also report the portion of direct emissions associated with electricity generated at any plant you own outside of the state border that is delivered to your customers in California. For transparency, you must also report the portion of your direct emissions associated with electricity from California plants delivered out of state. CARROT will help you calculate this information.

To determine your California indirect emissions, you must calculate the emissions associated with energy purchased and consumed within the state of California. Emissions associated with electricity purchased and delivered to end-users in California should be included in the calculation of your California-only indirect emissions, regardless of where the power is generated.

Example 4-1 illustrates how your reported direct and indirect emissions may change, depending on whether you choose to report your CA or your U.S. emissions.

Information on calculating direct emissions is provided in Chapter 5: Direct Emissions from Stationary Combustion.

**Example 4-1. Determining Geographic Boundaries:
An Electric Generation, Transmission and Distribution Company with facilities in
California and Nevada**

AB Power owns three electric generation facilities in California, two generating plants located in Nevada, and also has a transmission and distribution system through which it delivers electricity to customers in California.

The electricity that AB Power delivers to its customers comes from the company's own facilities located in California, its power plants located in Nevada, and from power purchases from other generators located in Oregon.

Reporting U.S. emissions:

When reporting all U.S. emissions, AB Power calculates all fugitive, process, mobile and stationary combustion emissions associated with its facilities in California and Nevada and reports these as direct emissions. All emissions associated with electricity purchased from Oregon generators and consumed by AB Power through T&D or other activities are reported as indirect emissions.

Reporting California emissions:

When reporting California emissions only, AB Power calculates all direct emissions, including fugitive, process, mobile and stationary combustion, of its facilities in California. AB Power also reports only the portion of direct emissions from its Nevada plants that is delivered to CA customers. All emissions associated with electricity purchased from Oregon generators and consumed by AB Power through T&D or other activities are reported as indirect emissions.

4.4 Geographic Boundaries vs. Organizational Boundaries

Your geographic boundary is not the same as your organizational boundary. Organizational boundaries reflect financial, legal and operational relationships. Geographic boundaries reflect the physical location of your facilities. If you have facilities located both inside and outside of California, reporting according to geographic boundaries may not capture all of your organization's emissions. Thus, we strongly recommend that organizations with operations inside and outside of California report their U.S. emissions.

4.5 Level of Detail in Reporting

As stated in the General Reporting Protocol, you must report, at a minimum, your California direct and indirect emissions in the appropriate categories. All data is reported through CARROT. However, the Registry recommends that you report your GHG emissions information at a sub-entity (i.e., business unit or facility) level. Reporting to this level of detail in CARROT will help to insure accuracy of your calculations, provide transparency and standardization, and thus help to lower your total costs of certification.

Chapter 5: Direct Emissions from Stationary Combustion

What you will find in Chapter 5	This chapter provides guidance on quantifying direct emissions from stationary combustion in the power/utility sector, including electric power generation, steam generation, auxiliary equipment, flaring and other related activities involving the combustion of fossil fuels or biomass fuels.
Information you will need	You may need information on your reporting under 40 CFR Part 75, total annual fuel use broken down by fuel type, electricity production, steam production and monitoring equipment information.

Power/utility companies that own or operate large combustion facilities may burn any combination of the following fuels: coal, oil, natural gas, biomass or others for the production of electricity and/or heat and steam. Although hydrocarbon fuel combustion emits CO₂, CH₄, and N₂O, the CO₂ emissions associated with stationary combustion facilities will likely make up the largest percentage of your CA or U.S. greenhouse gas inventory. This is because during the combustion process, nearly all the carbon contained in hydrocarbon fuels is converted to CO₂, regardless of the fuel type or combustion configuration.

The amount of CO₂ emitted from hydrocarbon combustion predominantly depends on the quantity of the fuel and carbon content of fuel consumed. To a lesser extent, the oxidation fraction of a particular fuel, under standard operating conditions and practices, also influences CO₂ emissions. (An oxidation fraction reflects an incomplete combustion process, to the extent that all the carbon contained in the fuel does not oxidize into CO₂ but remains as ash or unburned carbon.)

Non-fossil carbon bearing fuels (e.g., landfill gas, wood and wood waste, etc.) may also be combusted in stationary sources in the power/utility sector. Until international consensus is reached on the net impact on the climate from the combustion of biofuels, you are not required to include biomass CO₂ emissions in your total CO₂e direct emissions inventory. However, it is important to identify the contribution of these emissions as a part of your overall activities. Thus, you must identify and report biomass CO₂ emissions as “biogenic emissions,” in a category separate from fossil fuel emissions. Note that CH₄ and N₂O emissions from the combustion of biomass are not considered biogenic and should be calculated as part of your direct emissions inventory.

5.1 Stationary Combustion Equipment

The power/utility sectors use a number of stationary combustion technologies to generate, transmit, and distribute electricity and produce heat and/or steam. Power/utility companies also combust natural gas and other fossil fuels to transport, store, and distribute natural gas. Table 5.1 below lists examples of stationary combustion equipment that directly emit GHGs.

Table 5.1 Stationary Combustion Equipment

Technology Category	Source Type
Boilers	Natural gas boilers, residual or distillate oil boilers, coal-fired boilers (pulverized coal, fluidized bed, spreader stoker, tangentially fired, wall fired, etc.), biomass fired boilers, dual -fuel-fired boilers, and auxiliary boilers
Turbines	Combined cycle gas, simple cycle gas, combined heat and power, microturbines, steam turbines, and integrated gasification combined cycle
Internal Combustion Engines	Emergency and backup generators, reciprocating engines, compressors, firewater pumps, and black start engines
Flares	Natural gas, landfill gas, and waste gas
Other	Fuel cells, geothermal, anaerobic digesters, and refuse-derived fuels

5.2 GHG Emissions Quantification Methods

To quantify CO₂ emissions from stationary combustion sources, power/utility companies must use one or both of the following two methods:

1. Measurement-based methodology
2. Fuel use calculation-based methodology

For most power/utility companies, the information needed to quantify and report direct stationary combustion GHG emissions to the Registry should be available or easily derived from existing reporting activities. For major stationary sources, most power/utility companies already account for and report air pollution emissions to local, state and/or federal regulatory agencies, as well as total annual fuel use, and electricity, steam and heat production.⁴

Most large electric generating units have continuous emissions monitoring systems (CEMS) that track their CO₂ emissions. Smaller units, however, have not installed these monitors, but rely on fuel use data to determine their emissions. Because of these varying requirements, you may have to use both the measurement-based and the calculation-based methodologies to report to the Registry.

To maintain consistency with other programs, entities that are required to report emissions to the U.S. EPA according to 40 CFR Part 75 and/or state or local environmental agencies are *strongly encouraged* to report the same CO₂ emissions information to the CA Registry.

Whichever method or combination of methods are used to calculate your GHG emissions inventory, you should use the same reporting methodology from year to year to maintain consistency and comparability between inventory years.

5.2.1 Measurement-Based Methodology

Continuous emissions monitoring systems (CEMS) are the primary emissions monitoring method used in the power/utility sector. The 40 CFR Part 75 rule includes requirements for installing, certifying, operating, and maintaining CEMS for measuring and reporting SO₂, NO_x, CO₂, O₂, opacity, and volumetric flow.⁵ The Part 75 rule also includes requirements for measuring and reporting emissions when CEMS are not utilized.

⁴ 40 CFR Part 75 provides all the protocols and procedures for operating continuous emissions monitors and quantifying and reporting air pollution and CO₂ emissions to the U.S. EPA. U.S. EPA Clean Air Markets Division - Consolidated Part 72 and 75 Regulations <http://www.epa.gov/airmarkets/monitoring/consolidated/index.html>

⁵ U.S. EPA, Clean Air Markets Division, *Part 75 CEMS Field Audit Manual*, July 16, 2003.

You may use either of the following two CEMS configurations to determine annual CO₂ emissions:

1. CO₂ CEMS and a Flow Monitoring System that measure CO₂ concentration, volumetric gas flow, and CO₂ mass emissions.
2. O₂ CEMS and a Flow Monitoring System that measure O₂ concentration, volumetric gas flow, and O₂ mass emissions to calculate CO₂ emissions.

As previously stated, if you are required to use CEMs under 40 CFR Part 75, you should also measure and report your CO₂ emissions to the Registry using this method. You must also specify which CEMS configuration you are using to monitor your CO₂ emissions. If you do report using CEMs, you must continue to use CEMs for those same facilities each year to ensure consistency over time.

As discussed above, the Registry requires that participants identify and report biomass CO₂ emissions as “biogenic emissions,” separate from fossil fuel emissions. Thus, if you combust biomass fuels in any of your units using CEMS to report CO₂ emissions, you must calculate the emissions associated with the biomass fuels (Equation 5a) and subtract this from your total measured emissions (Equation 5b). You must report these separate from your fossil emissions, along with any other biogenic emissions.

Equation 5a				
Calculating Biomass Carbon Dioxide (CO₂) Emissions (Fuel Consumption is in MMBtu)				
Total Emissions (metric tons)	=	Fuel Consumed (MMBtu)	x Adjusted Emission Factor (kg CO ₂ /MMBtu)	x 0.001 metric tons/kg

Equation 5b		
Backing Out Biomass Carbon Dioxide (CO₂) Emissions from CEMS		
Total Emissions (metric tons)	=	Total CEMS CO ₂ Emissions (metric tons) - Total Biomass CO ₂ Emissions (metric tons)

Example 5-2 illustrates a case where biomass is co-fired and emissions are monitored through a CEMS.

Example 5-2. Biomass Co-Firing in a Unit with CEMS

An electric utility company operating in California reports the CO₂ emissions from its major electric generating facilities using the CEMS already installed on those units. At one of its natural gas-fired units it co-fires with wood; the emissions associated with each combustion activity are mixed in the exhaust stack and measured collectively by the CEMS device. To report its CO₂ emissions from this unit, the utility must calculate the portion of CO₂ emissions from combusting wood, and subtract it from the total emission measurement. To do so, the company must quantify the amount of biomass consumed by the unit, and multiply that value by the wood-specific CO₂ emission factor. This value is then subtracted from the total CO₂ emissions measured by the CEMS. See Equations 5a and 5b below.

Equation 5a		Calculating Biomass Carbon Dioxide (CO ₂) Emissions (Fuel Consumption is in MMBtu)					
Total Emissions (metric tons)	=	Fuel Consumed (MMBtu)	x	Adjusted Emission Factor (kg CO ₂ /MMBtu)	x	0.001 metric tons/kg	
Total Emissions (metric tons)	=	1,000,000 MMBtu	x	90.94 kg CO ₂ /MMBtu	x	0.001 metric tons/kg	= 90,940 metric tons CO ₂

Equation 5b		Subtract Biomass Carbon Dioxide (CO ₂) Emissions from CEMs			
Total Emissions (metric tons)	=	Total CEMs CO ₂ Emissions (metric tons)	-	Total Biomass CO ₂ Emissions (metric tons)	
Total Emissions (metric tons)	=	8,000,000 metric tons CO ₂	-	90,940 metric tons CO ₂	= 7,909,060 metric tons CO ₂

5.2.2 Fuel Use Calculation-Based Methodology

To calculate your GHG emissions based on fuel use, you must determine how much and what type of fuel was combusted, determine how much of the fuel is oxidized in the combustion process, and determine its CO₂ content.

To calculate CO₂, CH₄, and N₂O emissions from stationary combustion, you should:

1. Identify the annual consumption of each fossil and non-fossil fuel type combusted in your operations;
2. Apply a Heat Content factor to convert fuel use from physical units to energy units;
3. Calculate or select the appropriate emission factor for each fuel;
4. Calculate each fuel's CO₂ emissions and convert to metric tons;
5. Calculate each fuel's CH₄ and N₂O emissions, if any, and convert to metric tons; and
6. Convert CH₄ and N₂O emissions to CO₂ equivalents and sum all subtotals.

Each of these steps is explained in further detail below.

Step 1: Identify the annual consumption of each fossil and non-fossil fuel

First, determine your annual fuel use by fuel type, measured in terms of physical units (e.g., mass or volume). For stationary combustion sources, you may use one of two methods, listed below, from most accurate to least accurate. Note that while either one is acceptable for reporting to the Registry, as the methods decrease in accuracy, they also increase in the level of certification required.

Step 1a. Methods for Obtaining Fuel Use Data

Step 1a1. On-site measurements

Determine the amount of fuel combusted at each combustion unit by reading individual meters

located at the fuel input point. Then, sum the fuel use for each unit to arrive at the facility-wide fuel use. If you have a facility-wide fuel totalizer, you can use the amount of fuel from the totalizer.

Step 1a2. Calculate annual mass balance

Using fuel purchase records and your fuel inventory log, calculate your total fuel usage. Convert fuel purchase and storage data to estimates of actual fuel use using Equation 5d:

Equation 5c		Calculating Actual Annual Fuel Usage			
Total Annual Fuel Burned	=	Annual Fuel Purchases	+	[Fuel Stock at Beginning of Year - Fuel Stock at End of Year]	

Step 2: Convert fossil fuel use from physical units to energy units

At this point, your total fuel use is expressed in physical units (mass or volume). Before you can apply a CO₂ emission factor, you must first convert the physical units to heat content (HC), expressed in million British Thermal Units (MMBTU).

You can use one of three methods to report heating values:

1. Direct measurement according to industry-approved methods;
2. Fuel supplier-provided; and
3. Approved default factors.

Default heat content values for each fuel type are provided in Table 5.2, below. You should calculate heat content based on higher heating values (HHV). (See GRP for discussion of converting HHV to LHV).

Step 3: Apply or Derive an Appropriate CO₂ Emission Factors for Each Fuel

After determining the amount of fuel combusted (expressed in energy content, MMBTU), you must next determine the amount of CO₂ emitted into the atmosphere per unit of fuel. To calculate this information you can use an emission factor obtained from an approved source, listed in Step 3a. To derive your emission factor based on your specific fuel purchases, you follow the guidance in Step 3b.

Step 3a: To identify your general emission factor, you can use any of the three following methods. These are listed beginning with the most accurate:

- A. Monitoring over a range of conditions and deriving emission factors.** Periodic source testing according to industry-approved methods.
- B. Equipment manufacturer data.** Emission performance guaranteed by manufacturer testing and certification.
- C. Default emission factors.** Fuel-specific CO₂ emission factors representing average fuel and technology characteristics.

Table 5.1 Default CO₂ Emission Factors

Fossil Fuel	Emission Factor (kg CO ₂ /MMBtu)
Anthracite Coal	103.61
Bituminous Coal	93.50
Sub bituminous Coal	97.12
Lignite Coal	96.61
Coke	102.11
Natural Gas	53.05
Distillate Oil	73.14
Residual Oil	78.79
Kerosene	72.30
Petroleum Coke	102.11
LPG	62.99
Ethane	59.60
Propane	63.04
Isobutane	65.08
n-Butane	64.97
Geothermal ⁶	n.a.
Wood – dry	90.94
Landfill gas	52.07
Waste water treatment biogas	52.07

See sources noted for Table 5.2.

Step 3b: To derive your emission factor, follow this three-step process:

- 1. Determine the Carbon Content of the Fuel.** You can obtain this information either directly from your fuel supplier based on the actual content of the fuel you purchase, or you can use a default factor, provided in Table 5.2 below.
- 2. Multiply by an Oxidation Fraction.** Inefficiencies in the combustion process prevent all the carbon in fossil fuels from oxidizing into CO₂. As a result, a small fraction of the carbon remains unburned as soot or ash, but this is different for each fuel. To identify how much of the carbon in your fuel is oxidized, multiply your purchases of each fuel by its respective oxidation factor, identified in Table 5.2.
- 3. Convert to CO₂.** After determining the oxidized carbon content of a fuel, the last step is to convert from carbon emissions to carbon dioxide emissions. Multiply this amount by the molecular weight of CO₂ over carbon (44/12).

This process is outlined in Equation 5d below:

⁶ A study of California's geothermal power plants found the state average CO₂ emission rate to be roughly 150 lb/MWh. The newest generation of flash steam geothermal plants emit CO₂ at roughly 100 lb/MWh. There are no CO₂ emissions from binary systems, because any CO₂ present in the geothermal resource (steam or water) is reinjected into the earth.

Equation 5d

Emissions	$\sum_{i=1}^n$	Fuel _i x	HC _i x	[CC _i x	OF _i x	$\frac{CO_{2(m.w.)}}{C_{(m.w.)}}$]
=						

Where:

Fuel _i	=	Mass or Volume of the Fuel Type <i>i</i> Combusted
HC _i	=	Heat Content of Fuel Type <i>i</i> (energy / mass or volume of fuel)
CC _i	=	Carbon Content Coefficient of Fuel Type <i>i</i> (mass C / energy)
OF _i	=	Oxidation Fraction of Fuel Type <i>i</i>
CO _{2(m.w.)}	=	Molecular weight of CO ₂
C _(m.w.)	=	Molecular weight of C

Table 5.2: Default Values for Heat Content, Carbon Content, and Fraction of Carbon Oxidized for Fuels used for Electric Power Generation

Fossil Fuel	Heat Content (HHV)	Carbon Content	Fraction Oxidized
Coal and Coke	(Million Btu/Short Ton)	(kg C/MMBtu)	
Anthracite Coal	25.09	28.26	0.990
Bituminous Coal	24.93	25.50	0.990
Sub bituminous Coal	17.25	26.49	0.990
Lignite Coal	14.21	26.35	0.990
Coke	24.80	27.85	0.990
Natural Gas	(Btu/standard Ft³)	(kg C/MMBtu)	
Natural Gas	1,027.00	14.47	0.995
Petroleum	(Million Btu/Barrel)	(kg C/MMBtu)	
Distillate Oil	5.825	19.95	0.990
Residual Oil	6.287	21.49	0.990
Kerosene	5.670	19.72	0.990
Petroleum Coke	6.024	27.85	0.990
LPG	3.788	17.18	0.995
Ethane	2.916	16.25	0.995
Propane	3.824	17.20	0.995
Isobutane	4.162	17.75	0.995
n-Butane	4.328	17.72	0.995
Non-Fossil Fuel			
Solid	(Million Btu/Short Ton)	(kg C/MMBtu)	
Wood – dry	17.200	25.05	0.900
Gas	(Btu/standard Ft³)	(kg C/MMBtu)	
Landfill gas	502.500	14.20	0.995
Waste water treatment biogas	Varies (obtain from operator)	14.20	0.995

Sources:

Coal - Heat Contents and Carbon Content Coefficients based on the approach outlined in the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 2001*, EPA430-R-03-004, U.S. Environmental Protection Agency, Washington, DC, April 2003. The approach uses coal physical characteristics from the *CoalQual Database Version 2.0*, U.S. Geological Survey, 1998, and coal production data from the *Coal Industrial Annual*, U.S. Department of Energy, Energy Information Administration, Washington, DC, 2002 (year 2000 data used). Fractions Oxidized from Appendix A (Table A-15) of EPA inventory report.

Coke - Heat Content from the *Annual Energy Review 2002*, DOE EIA 0384(2002), U.S. Department of Energy, Energy Information Administration, Washington, DC, October 2003.

Carbon Content Coefficient and Fraction Oxidized from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 2001*, EPA430-R-03-004, U.S. Environmental Protection Agency, Washington, DC, April 2003. Values for coke are based on petroleum coke.

Natural Gas and Petroleum (except LPG) - Heat Contents from the *Annual Energy Review 2002*, DOE EIA 0384(2002), U.S. Department of Energy, Energy Information Administration, Washington, DC, October 2003. Carbon Content Coefficients and Fractions Oxidized from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 2001*, EPA430-R-03-004, U.S. Environmental Protection Agency, Washington, DC, April 2003.

LPG - Heat Contents and Carbon Content Coefficients for LPG components from Appendix B (Table B-9) of *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 2001*, EPA430-R-03-004, U.S. Environmental Protection Agency, Washington, DC, April 2003. Heat Content and Carbon Content Coefficient values for LPG based on values of components and assumed percent by volume of 6.5% ethane, 88% propane, 2.3% isobutane, and 3.0% n-butane. Fractions Oxidized from Appendix A (Table A-15) of EPA inventory report, Fractions Oxidized for LPG components assumed to be the same as for LPG

Wood - Heat Content and Fraction Oxidized from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 2001*, EPA430-R-03-004, U.S. Environmental Protection Agency, Washington, DC April 2003, Chapter 2 text describing the methodology used to calculate emissions from Wood Biomass and Ethanol Consumption. Carbon Content Coefficient calculated based on heat content and assumed 47.5% carbon in dry biomass also from the EPA inventory report (Chapter 2 text lists a range of 45% - 50%). The factors presented in Table B- 2 represent emissions from wood combustion only and do not include any emissions or sinks from wood growth or harvesting.

Gas - Heat Content for landfill gas based on *Emissions and Sinks: 1990 - 2001*, EPA430-R-03-004, U.S. Environmental Protection Agency, Washington, DC April 2003 and assumed landfill gas composition of 50% CH₄ and 50% CO₂ by volume. Heat Content for wastewater treatment gas could be calculated based on methane heat content and percent methane in the gas. Carbon Content Coefficients are the carbon content coefficient of methane from the EPA inventory report. Fraction Oxidized also from the EPA inventory report, assumed to be the same as natural gas.

Step 4: Apply CH₄ and N₂O emission factors for each fuel

During the hydrocarbon combustion process, N₂O formation follows complex pathways and depends on a variety of factors, including fuel type and combustion technology and configuration. CH₄ formation is usually dependent on conditions similar to those that create N₂O. Therefore, the following emission factors for CH₄ and N₂O are broken down by fuel type, combustion technology, and equipment configuration. This contrasts with CO₂ emission factors, which are almost exclusively dependent on fuel type.

Table 5.3 Default CH₄ and N₂O Factors

Fossil Fuel	Combustion Technology	Equipment Configuration	CH ₄ (kg CH ₄ /MMBtu)	N ₂ O (kg N ₂ O/MMBtu)
Coal	Pulverized Bituminous	Dry Bottom, wall fired	0.000699	0.000522
		Dry Bottom, tangentially fired	0.000699	0.001397
		Wet Bottom	0.000871	0.001397
	Bituminous Spreader Stokers	With and Without Reinjection	0.001048	0.000699
	Bituminous Fluidized Bed	Circulating Bed	0.001048	0.061063
		Bubbling Bed	0.001048	0.061063
	Bituminous Cyclone Furnace		0.000172	0.001569
	Lignite Atmospheric Fluidized Bed		NA	0.070874
Oil	Residual Fuel Oil/Shale Oil	Normal Firing	0.000848	0.000331
		Tangential Firing	0.000848	0.000331
	Distillate Fuel Oil	Normal Firing	0.000907	0.000358
		Tangential Firing	0.000907	0.000358
	Large Diesel Fuel Engines >447 kW		0.003674	NA
Natural Gas	Boilers		0.001021	0.000980
	Large Gas Fired Turbines >3 MW		0.003901	0.001361
	Large Dual Fired Engines		0.272155	NA

Source: U.S. EPA's Compilation of Air Pollutant Emission Factors, Vol. 1: Stationary Point and Area Sources. Converted from pounds to kilograms using the conversion factor of 0.453592.

Step 5. Calculate each fuel's CO₂ emissions and convert to metric tons

If your fuel consumption is expressed in MMBtu, use Equation 5e. If your fuel is expressed in mass units (i.e., gallons, short tons, cubic feet, etc.) use Equation 5f.

Equation 5e	Total CO ₂ Emissions (Fuel Consumption is in MMBtu)			
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CO ₂ /MMBtu)	x	Fuel Consumed (MMBtu)
			x	0.001 metric tons/kg

Equation 5f	Total CO ₂ Emissions (Fuel Consumption is in Mass Units)			
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CO ₂ /mass unit)	x	Fuel Consumed (mass unit)
			x	0.001 metric tons/kg

Step 6. Calculate each fuel's CH₄ and N₂O emissions, if any, and convert to metric tons

If your fuel consumption is expressed in MMBtu, calculate CH₄ emissions using Equation 5g and N₂O emissions using Equation 5h. If fuel consumption is expressed in mass units, use Equation 5i and 5j.

Note: if non-CO₂ gases are *de minimis* after they are converted to CO₂e and metric tons, you may choose to not report them to the Registry. Also, you are encouraged, but not *required* to report non-CO₂ emissions until your fourth calendar year of reporting to the Registry.

Equation 5g	Total CH₄ (Fuel Consumption is in MMBtu)			
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CH ₄ /MMBtu)	x	Fuel Consumed (MMBtu) x 0.001 metric tons/kg

Equation 5h	Total N₂O Emissions (Fuel Consumption is in MMBtu)			
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg N ₂ O/MMBtu)	x	Fuel Consumed (MMBtu) x 0.001 metric tons/kg

Equation 5i	Total CH₄ Emissions (Fuel Consumption is in Mass Units)			
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CH ₄ /Mass Units)	x	Fuel Consumed (Mass Units) x 0.001 metric tons/kg

Equation 5j	Total N₂O Emissions (Fuel Consumption is in Mass Units)			
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg N ₂ O/Mass Units)	x	Fuel Consumed (Mass Units) x 0.001 metric tons/kg

Step 7. Convert CH₄ and N₂O emissions to CO₂ equivalents and sum all subtotals

To incorporate and evaluate non-CO₂ gases in your GHG emissions inventory, you must convert the mass estimates of these gases to CO₂ equivalent. To do this, multiply the emissions in units of mass by global warming potential (GWP). Table 5.4 below lists the 100-year GWPs to be used to express emissions on a CO₂ equivalent basis.

Equation 5k	Converting Mass Estimates to Carbon Dioxide Equivalent		
Metric Tons of CO₂e	=	Metric Tons of GHG	x GWP

Table 5.4 Comparison of GWPs from the IPCC's Second and Third Assessment Reports		
Greenhouse Gas	GWP (SAR, 1996)	GWP (TAR, 2001)
CO ₂	1	1
CH ₄	21	23
N ₂ O	310	296
HFC-123	11,700	12,000
HFC-125	2,800	3,400
HFC-134a	1,300	1,300
HFC-143a	3,800	4,300
HFC-152a	140	120
HFC-227ea	2,900	3,500
HFC-236fa	6,300	9,400
HFC-43-10mee	1,300	1,500
CF ₄	6,500	5,700
C ₂ F ₆	9,200	11,900
C ₃ F ₈	7,000	8,600
C ₄ F ₁₀	7,000	8,600
C ₅ F ₁₂	7,500	8,900
C ₆ F ₁₄	7,400	9,000
SF ₆	23,900	22,000

Source: Intergovernmental Panel on Climate Change, Second Assessment Report (1996) and Third Assessment Report (2001).

5.2.3 Biogenic Emissions

As stated above, the Registry distinguishes between fossil fuel emissions (anthropogenic emissions) and non-fossil fuel emissions (biogenic emissions). In reporting your GHG emissions inventory, you should include all of your anthropogenic emissions in your report. Consistent with international practice at this time, you are also required to document your biogenic emissions used for stationary combustion, but you should report them separately from your direct emissions from stationary combustion. The same step-by-step procedure to determine GHG emissions from fossil fuels applies to non-fossil fuels.

For municipal solid waste-to-energy facilities (MSW), you must calculate your CO₂ emissions resulting from the incineration of waste of fossil fuel origin (e.g. plastics, certain textiles, rubber, liquid solvents, and waste oil) and include it in your GHG emissions inventory. However, your CO₂ emissions from combusting the biomass portion of MSW (e.g., yard waste, paper products, etc.) should be recorded as "biogenic emissions." Information on the biomass portion of MSW will be site-specific and should be obtained from a local waste characterization study.

5.2.4 Calculating Stationary Combustion for California Reporting

If you are reporting only your California emissions and you **generate and deliver** electricity to customers in California, you will calculate your stationary combustion emissions according to the guidance in this chapter for:

- All electricity generation from stations located in California.
- All electricity generated at stations outside of California, but delivered to customers in the state.

For California reporting, you should report all of the emissions associated with plants physically located in the state. For each plant that you own outside of California but that provides power to your customers in California, you should calculate your direct emissions and report the emissions associated with the portion of electricity you generate that is delivered to California. This is true

regardless of the physical location of the plant.

If you share ownership of the plant, you should only report the portion of emissions for which you are responsible, and the portion of emissions delivered to California. If you are reporting by equity share, this will correspond to your ownership share (Note: equity share is the preferred method of reporting for the power/utility sectors). For instance, if you have 50% ownership of a plant that delivers 80% of its output to California customers, you would report half of the emissions associated with 80% of the plant's output. If you are reporting using management control, you will report either 100% or none of the emissions associated with the output delivered to California.

Because the resources of the electricity deliveries are known, you should use the GHG emission factor associated with that purchase.

Example: Calculating Direct Emissions from Stationary Combustion **AB Power Corporation**

AB Power is an electric utility operating in California. It has two 800 MW generating units, one in California that burns natural gas and one at a mine mouth in Wyoming that combusts bituminous coal in dry bottom, wall-fired boilers. All of the generation from its California unit serves its California customers; 80% of the power generated at its Wyoming unit serves California customers. AB Power also owns a natural gas pipeline system in California, which includes natural gas compressor stations that combust natural gas.

Step 1: Identify all types of fuel directly combusted.

Table 5-6. Fuel Type, Sector, and Location		
Fuel	Sector	Location
Natural Gas	Electric Power Generation	California
Natural Gas	Natural Gas System	California
Coal	Electric Power Generation	Wyoming

Step 2: Determine annual consumption of each fuel.

AB Power directly measures the energy content (MMBTU) of the fuel used in both of its power plants and its natural gas compressor stations. From fuel purchase records, AB Power determined that last year it consumed 10,000,000 MMBtu of natural gas and 22,000,000 MMBtu of coal for power generation. It also consumed 1,000,000 MMBtu of natural gas in its compressor stations.

Step 3: Select the appropriate emission factors for each fuel from Tables 5.2 and 5.3.

Step 4: Calculate each fuel's carbon dioxide emissions

Equation 5i		Carbon Dioxide (CO ₂) Emissions from Natural Gas				
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CO ₂ /MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg
Total Emissions (metric tons)	=	53.05 kg CO ₂ /MMBtu	x	10,000,000 MMBtu	x	0.001 metric tons/kg = 530,500 metric tons CO ₂

Equation 5j		Carbon Dioxide (CO ₂) Emissions from Coal				
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CO ₂ /MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg
Total Emissions (metric tons)	=	93.5 kg CO ₂ /MMBtu	x	22,000,000 MMBtu	x	0.001 metric tons/kg = 2,057,000 metric tons CO ₂

Equation 5k		Total CO ₂ Emissions from Natural Gas				
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CO ₂ /MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg
Total Emissions (metric tons)	=	53.05 kg CO ₂ /MMBtu	x	1,000,000 MMBtu	x	0.001 metric tons/kg = 53,050 metric tons CO ₂

Total CO₂ from All Sources = 2,640,550 metric tons CO₂

Step 5: Calculate each fuel's methane and nitrous oxide emissions.

Equation 5l		Methane (CH ₄) Emissions from Natural Gas				
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CH ₄ /MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg
Total Emissions (metric tons)	=	0.001021kg CH ₄ /MMBtu	x	10,000,000 MMBtu	x	0.001 metric tons/kg = 10.21 metric tons CH ₄

Equation 5m		Methane (CH ₄) Emissions from Coal				
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CH ₄ /MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg
Total Emissions (metric tons)	=	0.000699 kg CH ₄ /MMBtu	x	22,000,000 MMBtu	x	0.001 metric tons/kg
					=	15.37 metric tons CH ₄

Equation 5n		Methane (CH ₄) Emissions from Natural Gas				
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CH ₄ /MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg
Total Emissions (metric tons)	=	0.001021 kg CH ₄ /MMBtu	x	1,000,000 MMBtu	x	0.001 metric tons/kg
					=	1.02 metric tons CH ₄

Total CH₄ from All Sources = 26.60 metric tons CH₄

Equation 5o		Nitrous Oxide (N ₂ O) Emissions from Natural Gas				
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg N ₂ O/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg
Total Emissions (metric tons)	=	0.000980 kg N ₂ O/MMBtu	x	10,000,000 MMBtu	x	0.001 metric tons/kg
					=	9.8 metric tons N ₂ O

Equation 5p		Nitrous Oxide (N ₂ O) Emissions from Coal				
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg N ₂ O/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg
Total Emissions (metric tons)	=	0.000522 kg N ₂ O/MMBtu	x	22,000,000 MMBtu	x	0.001 metric tons/kg
					=	11.48 metric tons N ₂ O

Equation 5q		Nitrous Oxide (N ₂ O) Emissions from Natural Gas				
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg N ₂ O/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg
Total Emissions (metric tons)	=	0.000980 kg N ₂ O/MMBtu	x	1,000,000 MMBtu	x	0.001 metric tons/kg
					=	0.98 metric tons N ₂ O

Total CH₄ from All Sources = 22.26 metric tons N₂O

In this case, it is likely that both methane and nitrous oxide emissions from stationary combustion are *de minimis*. See Chapter 10: Calculating De Minimis Emissions for more information on *de*

minimis emissions.

Step 6: Convert CH₄ and N₂O Emissions to CO₂e and sum the subtotals.

Equation 5r		Converting Mass Estimates to Carbon Dioxide Equivalent			
Metric Tons of CO ₂ e	=	Metric Tons of GHG	x	GWP	
Metric Tons of CO ₂	=				2,640,550 metric tons CO ₂
CH ₄ Tons of CO ₂ e	=	metric tons CH ₄	x	21	= 558.79 tons CO ₂ e
N ₂ O Tons of CO ₂ e	=	metric tons N ₂ O	x	310	= 6,901.84 metric tons CO ₂ e
Total					= 2,648,010.63 metric tons CO ₂ e

Step 7: If California-only reporting, calculate the portion of emissions associated with deliveries to California.

Equation 5r		Calculating Out of State Generation Delivered to California			
Metric Tons of CO ₂ e	=	Metric Tons of GHG	x	GWP	
Metric Tons of CO ₂	=				2,057,000 metric tons CO ₂
CH ₄ Tons of CO ₂ e	=	15.37 metric tons CH ₄	x	21	= 322.77 tons CO ₂ e
N ₂ O Tons of CO ₂ e	=	11.48 metric tons N ₂ O	x	310	= 3,558.8 metric tons CO ₂ e
Total					= 2,060, 881.57 metric tons CO ₂ e
					X 80% (portion of WY plant generation delivered to California)
Total					= 1,645,705.26 metric tons CO ₂ e

Equation 5r		Calculating In-State Generation Delivered to California			
Metric Tons of CO ₂ e	=	Metric Tons of GHG	x	GWP	
Metric Tons of CO ₂	=				530,500 metric tons CO ₂
CH ₄ Tons of CO ₂ e	=	10.21 metric tons CH ₄	x	21	= 214.41 tons CO ₂ e
N ₂ O Tons of CO ₂ e	=	9.8 metric tons N ₂ O	x	310	= 3038 metric tons CO ₂ e
Total					= 533,752.41 metric tons CO ₂ e
					+ 1,645,705.26 metric tons CO ₂ e
Total					= 2,179,457.67 metric tons CO ₂ e

Chapter 6: Direct Emissions from Processes

What you will find in Chapter 6:	This chapter provides guidance on quantifying direct emissions from power generation processes, including controlling emissions from power generation facilities.
Information you will need:	You may need information on your SO ₂ and NO _x emission control technology systems installed on your electric generating units, specifications of certain electric generation facilities as appropriate, and the quantity of calcium carbonate utilized.

In addition to stationary combustion emissions, you must account for any process-related GHG emissions that you have. These include:

- Sulfur dioxide (SO₂) scrubber emission control technology installed on many coal- and oil-fired electric generating units;
- NO_x emission control technologies such as selective catalytic reduction (SCR) and selective non catalytic reduction (SNCR) technologies; and
- Coal gasification at clean coal facilities, e.g., integrated gasification combined cycle (IGCC);
- Hydrogen production.

The Workgroup was unable to identify standardized methods to quantify process-related GHG emissions for hydrogen production, SCR, SNCR, and IGCC technologies.

6.1 SO₂ Scrubbers

Any wet flue gas desulfurization systems, fluidized bed boilers, or other emission controls with sorbent injection likely emit CO₂ during the SO₂ scrubbing process, from the use of calcium carbonate.

If you use CEMs to collect and report emissions data to the Registry for stationary combustion units that have SO₂ scrubbers installed, then the CEMs also capture the CO₂ emissions from the scrubbing.

If you are not reporting using CEMs and you have SO₂ scrubbers on your combustion units, you must follow the guidance in this chapter to quantify your process CO₂ emissions associated with SO₂ scrubbing.⁷

To calculate these process emissions follow the steps outlined below:

Step 1: Determine the Total Quantity of Sorbent Used

Using your company's purchase records, determine the total quantity of sorbent (tons of calcium carbonate (CaCO₃)) used each year. Identify your total sorbent inventory at the beginning of year, your total sorbent purchases during the year, and your total sorbent inventory at year end

Use these values in Equation 6a:

⁷ This methodology can be found in the U.S. EPA's CEMs guidelines and procedures. For more information on EPA's CEMS guidelines and procedures, reference (40 CFR Part 75).

Equation 6a		Annual Quantity of Sorbent Used		
Total Sorbent Used	=	Total inventory at beginning of year	Total inventory at end of year	Total purchases/acquisitions
		-	+	

Step 2: Calculate the Ratio of the Molecular Weight of CO₂ to the Sorbent

Divide the molecular weight of carbon dioxide (44) by the molecular weight of the calcium carbonate (100) and multiply by the calcium to sulfur stoichiometric ratio (1.00).

Equation 6b		Ratio of the Molecular Weight of CO ₂ /CaCO ₃		
Ratio of the Molecular Weight CO ₂ /CaCO ₃	=	Molecular Weight of CO ₂ (44)	Molecular Weight of CaCO ₃ (100)	Calcium to Sulfur Stoichiometric Ratio (1.00)
		/	x	

Step 3: Determine CO₂ Emissions and Convert to Metric Tons

Multiply the value obtained in Step 2 above by the total tons of CaCO₃ used to determine CO₂ emissions. Multiply by 0.907 to convert to metric tons. See Equation 6c below.

Equation 6c		Total Process Emissions (Metric Tons)		
Total Process CO ₂ Emissions (metric tons)	=	Calcium Carbonate Used (Tons)	Ratio of the Molecular Weight of CO ₂ /CaCO ₃	0.907 metric tons/short ton
		x	x	

Example: Calculating Process Emissions from SO₂ Scrubber Sorbent

AB Power owns an 800 MW coal-fired electric generating facility in Wyoming. To comply with the federal Acid Rain Program, it installed SO₂ scrubbers that use calcium carbonate as the sorbent for the scrubbers.

AB Power reports all of its CO₂ emissions to the Registry from this facility. To calculate its stationary combustion, it uses the fuel-based calculation method. Thus, it must also complete the following calculations to calculate the CO₂ emissions associated with operating its scrubbers, and report these as process emissions.

Step 1: Determine the Total Quantity of Sorbent Used

Based on company purchase records, AB Power determined that it used 10,000 tons of calcium carbonate at its Wyoming coal facility in its scrubber technology.

Table 6-1. Calcium Carbonate Use and Location	
Location	Quantity of Calcium Carbonate Used (Tons)
Wyoming	10,000

Step 2: Multiply the Total Quantity of Sorbent by the Ratio of the Molecular Weight of CO₂ to the Sorbent

Equation 6a		Annual Quantity of Sorbent Used		
Total Sorbent Used	=	Total inventory at beginning of year	- Total inventory at end of year	+ Total purchases/acquisitions
10,000 tons	=	[9000 (tons)	- 9000 (tons)	+ 10,000 (tons)

Equation 6b		Ratio of the Molecular Weight of CO ₂ /CaCO ₃			
Ratio of the Molecular Weight CO ₂ /CaCO ₃	=	Molecular Weight of CO ₂ (44)	/	Molecular Weight of CaCO ₃ (100)	x Calcium to Sulfur Stoichiometric Ratio (1.00)
Ratio of the Molecular Weight CO ₂ /CaCO ₃	=	44	/	100	x 1.00 = 0.44

Step 3: Determine CO₂ Emissions and Convert to Metric Tons

Equation 6c		Total Process Emissions (Metric Tons)			
Total Process CO ₂ Emissions (metric tons)	=	Calcium Carbonate Used (Tons)	x Calcium to Sulfur Stoichiometric Ratio (1.00)	x Molecular Weight of CO ₂ (44)/Molecular Weight of CaCO ₃ (100)	x 0.907 metric tons/short ton
Total Process CO ₂ Emissions (metric tons)	=	10,000 tons	x 1.00	x 0.44	x 0.907 = 3,991 metric tons CO ₂

Chapter 7: Direct Fugitive Emissions

What you will find in Chapter 7	This chapter provides guidance on quantifying fugitive emissions from electric power transmission and distribution, natural gas transmission and distribution and venting, and fuel storage and handling.
Information you will need	You may need information on your total annual purchases of SF ₆ , natural gas receipts and deliveries, and natural gas facility and/or equipment-specific information.

The natural gas sector includes the production, processing, transmission and storage, and distribution of natural gas. This chapter provides guidance on activities within the natural gas sector that occur within the power generators or electric utility's business operations, namely transmission, storage and distribution.

There are three types of emissions from the major equipment in the natural gas transmission, storage and distribution segments – fugitive emissions, vented emissions and combustion emissions.

CH₄ and CO₂ are emitted from natural gas systems as a result of normal operations, routine maintenance, and system upsets. Whenever the natural gas moves through valves under high pressure, methane can escape to the atmosphere. Compressor stations in transmission and storage are one of the largest sources of fugitive emissions. Another potentially significant source of fugitive emissions is from leaks in underground pipelines due to corrosion, material defects and joint and fitting defects/failures.

Also, in many instances, gas is vented to the atmosphere as part of normal operations. For example, pneumatic devices, that regulate pressure in the natural gas system regularly bleed small amounts of gas to the atmosphere as they open and close their valves. Also common is the practice of shutting down a compressor and purging the gas in the compression chamber to the atmosphere.

Thus, fugitive emissions are unintentional releases of GHGs, for instance from joints, seals, and gaskets. Fugitive emissions from the power/utility sector include:

1. methane (CH₄) and carbon dioxide (CO₂) emissions from natural gas transmission, storage and distribution systems⁸;
2. sulfur hexafluoride (SF₆) from electricity transmission and distribution systems;
3. CH₄ from fuel handling and storage;
4. hydrofluorocarbons (HFCs) from air conditioning and refrigeration systems (both stationary and mobile); and
5. PFCs and HFCs from fire suppression equipment.

These sources are listed by segment, facility and equipment in Table 7.1 below.

This chapter provides guidance on quantifying fugitive emissions from:

⁸ Carbon dioxide may be emitted from fugitive sources due to the concentration of CO₂ in the gas stream. Also, methane emitted from buried pipelines is partially oxidized to form CO₂ as it passes through the surrounding soil.

- Natural gas transmission, storage and distribution systems,
- Electricity transmission and distribution systems, and
- Fuel handling and storage.

You must also include vented emissions when performing fugitive emissions calculations, either included as part of your total fugitive emissions, or reported separately as “vented” emissions.

Reporters should consult the General Reporting Protocol for guidance on calculating and reporting direct fugitive emissions from:

- **air conditioning and refrigeration systems** (both stationary and mobile)
- **fire suppression equipment.**

Note: For most power/utility companies, CH₄ emissions from fuel handling and storage and emissions of PFCs/HFCs may be de minimis. For information on estimating the impact of these emissions, see Chapter 10: Calculating De Minimis Emissions.

Table 7.1 Fugitive Emission Sources within Power/Utility Sectors

Fugitive CH ₄ and CO ₂ Transmission, Storage and Distribution Sources			
Segment	Facilities	Equipment	
Natural Gas Transmission	Transmission Pipeline Networks, Compressor Stations, Meter and Pressure Regulating Stations	Vessels, Compressors, Pipelines, Meters/Pressure Regulators, Pneumatic Devices, Valves, Flanges, Seals and Other Pipe Fittings	
Natural Gas Storage	Underground Injection/Withdrawal Facilities, and Liquefied Natural Gas (LNG) Facilities	Wellheads, Vessels, Compressors, Dehydrators, Heaters, Pneumatic Devices, Valves, Flanges, Seals and Other Pipe Fittings	
Natural Gas Distribution	Main and Service Pipeline Networks, Meter and Pressure Regulating Stations	Pipelines, Meters and Pressure Regulators, Pneumatic Devices, Customer Meters, Valves, Flanges, Seals and Other Pipe Fittings	
Vented CH ₄ Transmission, Storage and Distribution Sources			
Segment	Facilities	Equipment	
Natural Gas Transmission	Transmission Pipeline Networks, Compressor Stations, Meter and Pressure Regulating Stations	Station Venting, Dehydrator Vents, Pipeline Venting, Pneumatic Devices, Mishaps (diggins)	
Natural Gas Storage	Underground Injection/Withdrawal Facilities, and Liquefied Natural Gas (LNG) Facilities	Station Venting, Pneumatic Devices, Dehydrator Vents	
Natural Gas Distribution	Main and Service Pipeline Networks, Meter and Pressure Regulating Stations	Pipeline Venting, Pneumatic Devices, Pressure Relief Valves, Mishaps (diggins)	
Fugitive SF ₆ Sources			
Segment	Equipment		
Electricity Transmission	Circuit Breakers, Current-Interruption Equipment, Transmission Lines, Transformers, Substations		
Electricity Distribution	Circuit Breakers, Current-Interruption Equipment, Distribution Lines, Transformers, Substations		
Other Fugitive Emission Sources			
Segment	Facilities	Source	Emissions
Fuel Handling and Storage	Electric Generation Facilities, Fuel Storage Facilities	Coal Piles, Biomass Piles	CH ₄
Stationary and Mobile Cooling and Refrigeration	Electric Generation Facilities, Office Buildings, Mobile Sources	Air Conditioning and Refrigeration Systems	HFCs
Fire Extinguishers	Electric Generation Facilities	Total Flooding Fire Extinguishing Systems	PFCs and HFCs

7.1 Fugitive Emissions from Electricity Transmission and Distribution

Within the electric power industry, SF₆ is the preferred gas for electrical insulation, arc quenching and current interruption equipment used to transmit and distribute electricity. SF₆ is extremely stable and long lasting, and is also a potent greenhouse gas. It is estimated that the electric power industry uses about 80% of the SF₆ produced worldwide, with circuit breaker applications accounting for most of this amount.⁹

Fugitive SF₆ emissions from the electric utility industry are the result of normal operations and routine maintenance, as well as the use of older equipment. SF₆ can escape to the atmosphere

⁹ Other uses of SF₆ include: semiconductor processing, blanket gas for magnesium casting, reactive gas in aluminum recycling to reduce porosity, thermal and sound insulation, airplane tires, spare tires, "air sole" shoes, scuba diving voice communication, leak checking, atmospheric tracer gas studies, ball inflation, torpedo propeller quieting, wind supersonic channels, and high voltage insulation for many other purposes, such as AWACS radar domes and X-ray machines.

during normal operations, releases from properly functioning equipment (due to both static and dynamic operation) and old and/or deteriorated gaskets or seals. SF₆ can also escape when gas is either transferred into or extracted from equipment for disposal, recycling, or storage.

7.2 Fugitive Emissions from Fuel Handling and Storage

Fugitive emissions from fuel handling and storage are the result of

- CH₄ desorption from coal handling and storage;
- CH₄ and N₂O from decomposing
- Other

Fugitive emissions from fuel handling and storage will likely be *de minimis* for power/utility entities. For help in determining whether your fugitive CH₄ emissions from fuel handling and storage are *de minimis*, see Chapter 10: Calculating De Minimis Emissions.

7.2.1 Coal Handling & Storage

In the course of mining, transporting and storing coal used for power generation, methane is emitted from underground mining, surface mining, and post-mining activities. Some methane remains in the coal after it is removed from the mine and can be emitted as the coal is transported, processed, and stored. Depending on the characteristics of the coal and the way it is handled after leaving the mine, the amount of methane released during post-mining activities can be significant and can continue for weeks or months. The greatest releases occur when coal is crushed, sized, and dried in preparation for industrial or utility uses.¹⁰ The actual amount of gas that escapes into the atmosphere will be a function of the rate of methane desorption, the coal's original gas content, and the amount of time elapsed before coal combustion occurs.

7.2.2 Biomass Handling & Storage

In the handling and storage of biomass, methane is formed where anaerobic digestion occurs. Whether or not anaerobic conditions occur in the pile largely depends on the characteristics of the pile and its surroundings (height, surface, temperature) and the content of the biomass itself (particle size, density, moisture content). Biomass piles may also be a source of nitrous oxide emissions during the first stage of decomposition.¹¹

7.3 Quantifying Fugitive CH₄ Emissions from the Natural Gas Sector

This section provides default methods for you to quantify fugitive CH₄ and CO₂ emissions from natural gas transmission, storage and distribution operations.

Two default quantification methods are available and are listed in order of data requirements and accuracy:

1. Equipment-level average emission factors
2. Facility-level average emission factors

Both are acceptable for reporting to the Registry, although the equipment-level average may be more accurate. Note that the costs of certification may increase with the decreased level of accuracy.

¹⁰ U.S. EPA, 1990.

¹¹ Consistent with international practice, CO₂ emissions from the combustion of biomass fuels used in electricity generation must be quantified and reported as biogenic emissions, but are not included in your total GHG emissions inventory, which tracks anthropogenic emissions. For more information on calculating these emissions, see *Chapter 5: Direct Emissions from Stationary Combustion*.

7.3.1 Equipment-Level Average Emission Factors

This method calculates your emissions based on gas infrastructure data and average emission factors. To use this method you need to know detailed information about your equipment, including the number of miles of transmission pipe, number of compressor stations, number of storage facilities, miles of distribution pipe (by type), and total number of services (by type).

With this inventory identified, you can calculate your fugitive CH₄ emissions using the following five step process:

1. Identify the natural gas infrastructure at the equipment level.
2. Determine the appropriate emission factors.
3. Calculate and sum CH₄ emissions and convert to metric tons.
4. Calculate and sum CO₂ emissions and convert to metric tons.
5. Convert CH₄ emissions to CO₂ equivalents and sum all subtotals.

Each of these steps is described in greater detail below.

Step 1: Identify your natural gas infrastructure at the equipment level

First determine all of the equipment that makes up your natural gas infrastructure.

Prepare an inventory of your equipment, including:

Natural Gas Transmission Equipment:

1. miles of transmission pipeline
2. transmission compressor stations and storage compressor stations
3. liquefied natural gas (LNG) storage stations
4. natural gas storage stations
5. miles of gathering pipeline

Natural Gas Distribution Equipment:

1. miles of cast iron main pipeline
2. miles of unprotected steel main pipeline
3. miles of protected steel main pipeline
4. miles of plastic main pipeline
5. number of customer connections
6. number of unprotected steel services
7. number of protected steel services

Step 2: Determine the appropriate emission factors

From Table 7.2, identify the appropriate emission factor for each equipment type. If you have an emission factor that is more accurate than the default, you can also use this emission factor.

Table 7.2 Equipment-Level Average Fugitive Emission Factors

Equipment	Original Emission Factor	Original Annual Units	Converted Emission Factor	Converted Annual Units
Compressor Stations (Storage)				
Stations	7,850.06	Mscf/station	331,900.33	Lb CH ₄ /station
Reciprocating Compressors	7,707.34	Mscf/compressor	325,866.34	Lb CH ₄ /station
Centrifugal Compressors	11,159.15	Mscf/compressor	471,808.65	Lb CH ₄ /station
Compressor Stations (Transmission)				
Station	3,203.97	Mscf/station	135,463.85	Lb CH ₄ /station
Reciprocating Compressors	5,549.83	Mscf/compressor	234,646.60	Lb CH ₄ /compressor
Contrifugal Compressors	11,061.33	Mscf/compressor	467,672.82	Lb CH ₄ /compressor
Pipeline				
Cast Iron Mains	238.7	Mscf/mile	10,092.24	Lb CH ₄ /mile
Unprotected Steel Mains	110.19	Mscf/mile	4,658.83	Lb CH ₄ /mile
Protected Steel Mains	3.12	Mscf/mile	131.91	Lb CH ₄ /mile
Plastic Mains	19.3	Mscf/mile	816.00	Lb CH ₄ /mile
Services				
Unprotected Steel Services	1.7	Mscf/service	71.88	Lb CH ₄ /service
Protected Steel Services	0.18	Mscf/service	7.61	Lb CH ₄ /service
Plastic Services	0.01	Mscf/service	0.42	Lb CH ₄ /service
Copper Services	0.25	Mscf/service	10.57	Lb CH ₄ /service
Customer Meters				
Residential	0.1385	Mscf/meter	5.86	Lb CH ₄ /meter
Commercial/Industry	0.0479	Mscf/meter	2.03	Lb CH ₄ /meter

Source: EPA/GRI, 1996. Conversion assumes 42.28 lbs CH₄/Mscf.

Step 3: Calculate and sum CH₄ emissions and convert to metric tons

For each component, multiply the number of pieces by the appropriate emission factor. Sum the emissions from each equipment components to obtain total CH₄ emissions from natural gas transmission (Equation 7a) and distribution (Equation 7b) systems. Divide the number of lbs/CH₄ obtained by 2,204.6 lbs/metric ton to obtain metric tons of CH₄ produced.

Equation 7a		Total CH ₄ Emissions from Major Transmissions System Equipment			
Total CH ₄ Emissions from Compressor Stations (Transmission) (metric tons)	=	CH ₄ Emission Factor (lb CH ₄ /station)	x	Number of Stations	/ 2,204.6 lbs/metric ton
Total CH ₄ Emissions from Compressor Stations (Storage) (metric tons)	=	CH ₄ Emission Factor (lb CH ₄ /station)	x	Number of Stations	/ 2,204.6 lbs/metric ton

Equation 7b		Total CH ₄ Emissions from Major Distribution System Equipment			
Total CH ₄ Emissions from Cast Iron Natural Gas Distribution Pipeline (metric tons)	=	10,092.24 lb CH ₄ /mile	x	Miles of Cast Iron Pipeline	/ 2,204.6 lbs/metric ton
Total CH ₄ Emissions from Unprotected Steel Natural Gas Distribution Pipeline (metric tons)	=	4,658.83 lb CH ₄ /mile	x	Miles of Unprotected Steel Pipeline	/ 2,204.6 lbs/metric ton
Total CH ₄ Emissions from Protected Steel Natural Gas Distribution Pipeline (metric tons)	=	131.91 lb CH ₄ /mile	x	Miles of Protected Steel Pipeline	/ 2,204.6 lbs/metric ton
Total CH ₄ Emissions from Plastic Natural Gas Distribution Pipeline (metric tons)	=	816.00 lb CH ₄ /mile	x	Miles of Plastic Pipeline	/ 2,204.6 lbs/metric ton
Total CH ₄ Emissions from Natural Gas Distribution Residential Meters (metric tons)	=	5.86 lb CH ₄ /residential meter	x	Number of Residential Meters	/ 2,204.6 lbs/metric ton
Total CH ₄ Emissions from Natural Gas Distribution Commercial Meters (metric tons)	=	2.03 lb CH ₄ /commercial meters	x	Number of Commercial Meters	/ 2,204.6 lbs/metric ton
Total CH ₄ Emissions from Natural Gas Distribution Unprotected Steel Services (metric tons)	=	71.88 lb CH ₄ /service	x	Number of Unprotected Steel Services	/ 2,204.6 lbs/metric ton
Total CH ₄ Emissions from Natural Gas Distribution Protected Steel Services (metric tons)	=	7.61 lb CH ₄ /service	x	Number of Protected Steel Services	/ 2,204.6 lbs/metric ton
Total CH ₄ Emissions from Natural Gas Distribution Plastic Services (metric tons)	=	0.42 lb CH ₄ /service	x	Number of Protected Steel Services	/ 2,204.6 lbs/metric ton
Total CH ₄ Emissions from Natural Gas Distribution Copper Services (metric tons)	=	10.57 lb CH ₄ /service	x	Number of Protected Steel Services	/ 2,204.6 lbs/metric ton

Step 4: Calculate Fugitive CO₂ Emissions

Because of the concentration of CO₂ in the natural gas stream, CO₂ is emitted as a result of leaks and valves in the natural gas system. CO₂ also forms as a result of partial oxidization of CH₄ releases from buried pipelines as it travels underground through the soil.

Use Equations 7c and 7d to calculate the total CO₂ emissions from oxidation and leaks.

Equation 7c	Total CO ₂ Emissions From Distribution System Oxidation and Leaks			
Total CO ₂ Emissions for Natural Gas Distribution Pipeline (metric tons)	=	CO ₂ Oxidation Emission Factor (lb CO ₂ /mile)	x Miles of Pipeline	/ 2,204.6 lbs/metric ton
Total CO ₂ Emissions for Natural Gas Distribution Pipeline (metric tons)	=	CO ₂ Leak Emission Factor (lb CO ₂ /mile)	x Miles of Pipeline	/ 2,204.6 lbs/metric ton
Total CO ₂ Emissions for Natural Gas Distribution Services (metric tons)	=	CO ₂ Oxidation Emission Factor (lb CO ₂ /mile)	x Miles of Pipeline	/ 2,204.6 lbs/metric ton
Total CO ₂ Emissions for Natural Gas Distribution Services (metric tons)	=	CO ₂ Leak Emission Factor (lb CO ₂ /mile)	x Miles of Pipeline	/ 2,204.6 lbs/metric ton

Equation 7d	Total CO ₂ Emissions From Transmission Pipeline Oxidation and Leaks			
Total CO ₂ Emissions for Natural Gas Transmission Pipeline (metric tons)	=	CO ₂ Oxidation Emission Factor (lb CO ₂ /mile)	x Miles of Pipeline	/ 2,204.6 lbs/metric ton
Total CO ₂ Emissions for Natural Gas Transmission Pipeline (metric tons)	=	CO ₂ Leak Emission Factor (lb CO ₂ /mile)	x Miles of Pipeline	/ 2,204.6 lbs/metric ton

Step 5: Convert CH₄ emissions to CO₂ equivalents and sum all subtotals

Next, convert the emissions from each non-CO₂ gas in your GHG emissions inventory to their CO₂ equivalent. Multiply the CH₄ emissions by its Global Warming Potential. If non-CO₂ gases are *de minimis* when converted to CO₂e, you may choose to report them to the Registry. Also, you are not *required* to report non-CO₂ gases until the fourth year that you report emissions to the Registry.

Equation 7e	Converting Mass Estimates to Carbon Dioxide Equivalent		
Metric Tons of CO ₂ e	=	Metric Tons of GHG	x GWP

7.3.2 Facility-Level Average Emission Factors

This method relies on aggregate facility-level data and average emission factors. Required facility-level data include the number of facilities you have, categorized by gas storage, gas transmission pipelines and gas distribution pipelines.

Calculate your fugitive emissions using the following five steps:

1. Identify the number and types of facilities that make up your natural gas system.
2. Determine the appropriate emission factors.
3. Calculate CH₄ emissions and convert to metric tons.
4. Calculate CO₂ Emissions.
5. Convert CH₄ emissions to CO₂ equivalents and sum all subtotals.

Each of these steps is described in greater detail below.

Step 1: Identify the number and types of facilities that make up your natural gas system

First, identify all of the facilities that make up your natural gas system including storage, transmission and distribution. Determine the number of each of the following:

- natural gas storage facilities,
- miles of natural gas transmission pipeline, and
- miles of natural gas distribution pipeline.

Step 2: Determine the appropriate emission factors

For each type of facility, identify the appropriate CH₄ or CO₂ emission factor. Use either a default provided in Tables 7.3 and 7.4 or you can use your own emission factor, if it is more accurate than the default.

Table 7.3: Facility-Level Average Fugitive CH₄ Emission Factors

Source	Emissions	Annual Units	Precision	Gas Content Basis of Factor
Gas storage stations	1,489,000	lb CH ₄ /station	57	93.4 mole % CH ₄
Gas transmission pipelines	7,923	lbCH ₄ /mile	84	93.4 mole %
Gas distribution pipelines	3,551	lb CH ₄ /mile	48	93.4 mole %

Source: American Petroleum Institute, Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry, February 2004.

Source: Shires, T.M. and C.J. Loughran. *GHGCalc Version 1.0 Emission Factor Documentation*, Draft, Gas Technology Institute (GTI), January 2002, Tier 1 fugitive emission factors from Table 4-26.

Precision is based on a 90% confidence interval from the data used to develop the original emission factor.

Table 7.4: Facility-Level Average Fugitive CO₂ Emission Factors

Segment	Emissions	Annual Units
Distribution Pipeline		
CO ₂ from oxidation	1,205	lb CO ₂ /mile
CO ₂ from pipeline leaks	105.7	lb CO ₂ /mile
Distribution Services		
CO ₂ from oxidation	0.64	lb CO ₂ /mile
CO ₂ from service leaks	0.758	lb CO ₂ /mile
Transmission Pipeline		
CO ₂ from oxidation	7.59	lb CO ₂ /mile
CO ₂ from pipeline leaks	1.522	lb CO ₂ /mile

Source: American Petroleum Institute, Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry, February 2004.

Source: Shires, T.M. and C.J. Loughran. *GHGCalc Version 1.0 Emission Factor Documentation*, Draft, Gas Technology Institute (GTI), January 2002, Tier 1 fugitive emission factors from Table 4-26.

Step 3: Calculate CH₄ emissions and convert to metric tons

To develop estimates of CH₄ emissions, multiply facility data by the appropriate emission factor. Do this for each facility type (i.e., storage, transmission and distribution). Sum all emissions to obtain total CH₄ emissions from natural gas systems in lbs CH₄. Divide the number of lbs CH₄ obtained by 2,204.6 lbs/metric ton to obtain metric tons of CH₄ produced.

Equation 7f		Total CH ₄ Emissions from Fugitive Leaks		
Total CH ₄ Emissions for Natural Gas Storage Facilities (metric tons)	= CH ₄ Emission Factor (lb CH ₄ /facility)	x	Number of Facilities	/ 2,204.6 lbs/metric ton
Total CH ₄ Emissions for Natural Gas Transmission Pipeline (metric tons)	= CH ₄ Emission Factor (lb CH ₄ /mile)	x	Miles of Pipeline	/ 2,204.6 lbs/metric ton
Total CH ₄ Emissions for Natural Gas Distribution Pipeline (metric tons)	= CH ₄ Emission Factor (lb CH ₄ /mile)	x	Miles of Pipeline	/ 2,204.6 lbs/metric ton

Step 4: Calculate Fugitive CO₂ Emissions

Sum your CO₂ emission to obtain total CO₂ emission from natural gas transmission and distribution systems in lbs CO₂. Divide the number of lbs CO₂ obtained by 2,204.6 lbs/metric ton to obtain metric tons of CO₂ produced.

Equation 7g		Total CO ₂ Emissions From Transmission Pipeline Oxidation and Leaks		
Total CO ₂ Emissions for Natural Gas Transmission Pipeline (metric tons)	= CO ₂ Oxidation Emission Factor (lb CO ₂ /mile)	x	Miles of Pipeline	/ 2,204.6 lbs/metric ton
Total CO ₂ Emissions for Natural Gas Transmission Pipeline (metric tons)	= CO ₂ Leak Emission Factor (lb CO ₂ /mile)	x	Miles of Pipeline	/ 2,204.6 lbs/metric ton

Equation 7h		Total CO ₂ Emissions From Distribution System Oxidation and Leaks		
Total CO ₂ Emissions for Natural Gas Distribution Pipeline (metric tons)	= CO ₂ Oxidation Emission Factor (lb CO ₂ /mile)	x	Miles of Pipeline	/ 2,204.6 lbs/metric ton
Total CO ₂ Emissions for Natural Gas Distribution Pipeline (metric tons)	= CO ₂ Leak Emission Factor (lb CO ₂ /mile)	x	Miles of Pipeline	/ 2,204.6 lbs/metric ton
Total CO ₂ Emissions for Natural Gas Distribution Services (metric tons)	= CO ₂ Oxidation Emission Factor (lb CO ₂ /mile)	x	Miles of Pipeline	/ 2,204.6 lbs/metric ton
Total CO ₂ Emissions for Natural Gas Distribution Services (metric tons)	= CO ₂ Leak Emission Factor (lb CO ₂ /mile)	x	Miles of Pipeline	/ 2,204.6 lbs/metric ton

Step 5: Convert CH₄ emissions to CO₂ equivalents and sum all subtotals.

For each non-CO₂ gas, convert the mass estimates to CO₂ equivalent by multiplying the emissions in units of mass its GWP. If non-CO₂ gases are *de minimis* when converted to CO₂e, you may choose to not report them to the Registry. Also, you are not *required* to report non-CO₂ gases until the fourth year that you report emissions to the Registry.

Equation 7i	Converting Mass Estimates to Carbon Dioxide Equivalent		
Metric Tons of CO ₂ e	=	Metric Tons of GHG	x GWP (SAR, 1996, TAR 2001))

7.5 Quantifying Fugitive SF₆ Emissions from Electricity Transmission and Distribution

To calculate your fugitive SF₆ emissions from electricity transmission and distribution operations, you should use the Mass Balance Approach, as outlined in the U.S. EPA SF₆ Emission Reduction Partnership for Electric Power Systems. The complete methodology is provided in Appendix A to this protocol. An overview of the process is provided below.

7.5.1 Mass Balance Approach

This method uses a mass balance approach to calculate total fugitive SF₆ emissions.

Calculate your fugitive SF₆ emissions using the following six-step process:

1. Determine Change in SF₆ Inventory.
2. Determine Purchases/Acquisitions of SF₆.
3. Determine Sales/Disbursements of SF₆.
4. Determine Total Annual Emissions.
5. Convert SF₆ Emissions to CO₂ equivalents.
6. Determine Emission Rate (optional).

Chapter 8: Indirect Emissions from Energy Purchased and Consumed

What you will find in Chapter 8	This chapter provides guidance on quantifying indirect emissions from electricity purchased and consumed by companies in the power/utility sector. Indirect emissions are those that are a consequence of the actions of a reporting entity, but are produced by sources owned or controlled by another entity.
Information you will need	You may need information on your total annual purchases and deliveries of electricity.

This chapter provides guidance for you to quantify the indirect emissions associated with the portion of your purchased and wheeled electricity (for resale to end-users) consumed by your transmission and/or distribution system (through line losses).

8.1 T&D Line Loss Sources in the Power/Utility Sectors

If you own transmission and/or distribution assets, you are responsible to report the electricity losses that occur in those systems. Since these losses are classified as “consumption” of the electricity, they are categorized as indirect emissions. Sources of transmission and distribution line losses include those areas and sources listed in Table 8.1 below.

Table 8.1: Transmission and Distribution Line Loss Sources

Segment	Facilities	Equipment
Electricity Transmission	Feeders and Transmission Lines	Conductors
Electricity Distribution	Distribution Systems and Substations	Transformers

You must report the following indirect emissions:

1. *Indirect Emissions Associated with Transmission and/or Distribution Losses.* These are the emissions associated with 1) the portion of the electricity purchased for resale to end-users that is consumed by your T&D system, and 2) the portion of wheeled electricity that is consumed by your T&D system.¹²
2. *Purchased electricity, steam or heat for own consumption.* These are the emissions associated with the generation of purchased electricity, steam/heat that is consumed in equipment or operations owned or controlled by your organization (e.g., office buildings).

Reporters should consult the General Reporting Protocol for guidance on calculating and reporting indirect emissions from:

- electricity, steam or heat purchased for your own consumption.

If you are reporting only California emissions, you should follow the steps in this chapter to calculate the emissions associated with T&D Losses serving customers in California only and energy purchased and consumed at facilities in California only.

8.2 Quantifying Indirect Emissions Associated with Transmission & Distribution

¹² Wheeled electricity includes direct access (customer choice programs) where the T&D utility only transmits and/or distributes the power.

Losses

This section provides a default method for quantifying indirect GHG emissions associated with your consumption of purchased and wheeled electricity on your T&D system (T&D losses).

If you own and/or operate a transmission and/or distribution system, you must report the portion of indirect emissions associated with the amount of purchased and wheeled electricity that corresponds to your entity-wide T&D losses.

Please note: you do not need to account for the T&D losses associated with electricity that you generate and sell to end-users. These emissions are already reported in your inventory as direct stationary combustion emissions.

However, if you *purchase* electricity and *resell* it to end-users, you must report the indirect emissions associated with transmission and/or distribution of this electricity. You should also separately report the indirect emissions associated with transmission and distribution of wheeled electricity (including direct access).

8.2.1 Sources of Information on T&D Losses

Your organization may already track the data necessary to report using this methodology for state, federal or independent system operator (ISO) reporting purposes. For example, your organization may be required to report to the Federal Energy Regulatory Commission (FERC) under *FERC FORM 1 - Annual Report of Major Electric Utility*, to the U.S. Energy Information Administration (EIA) under *The Annual Electric Power Industry Report, Form EIA-861* or Public Electric Utility Database Form EIA-412.

If you currently report FERC FORM 1, all information required to use this methodology is contained on:

Page 401: *Electrical Energy Account*.
Page 327: *Purchased Power*, and
Page 328 *Transmission of Electricity for Others*.

8.2.2 Calculate T&D Losses

Calculate your **transmission and/or distribution losses** using the following fourteen steps:

1. Identify the Total Net Generation.
2. Identify the Total Purchases from Electricity Suppliers.
3. Identify Exchanges (Net).
4. Identify Wheeled (Net).
5. Identify Transmission by Others (Losses).
6. Identify Total Sources.
7. Identify Retail Sales to Ultimate Customers.
8. Identify Sales for Resale.
9. Identify Energy Furnished Without Charge.

10. Identify Energy Consumed by Respondent Without Charge.
11. Identify Energy Consumed by Facility (Independent Power Producers or Qualifying Facility).
12. Identify Total Energy Losses.
13. Identify T&D Loss Factor.
14. Identify Portion of Losses Attributable to Purchases and Wheeled Power.

Each of the steps to calculate your transmission and/or distribution losses is described in greater detail below.

Step 1: Identify Your Total Net Generation

Determine your net generation (gross generation minus plant use) in megawatt hours (MWh).

Step 2: Identify the Total Purchases from Electricity Suppliers

Add your total purchases (MWh) from all electricity suppliers including: nonutility power producers and power marketers, municipal departments and power agencies, cooperatives, investor-owned utilities, political subdivisions, state agencies and power pools, and marketing agencies.

Step 3: Identify Exchanges (Net)

Determine the net amount of energy exchanged in MWh. Calculate the difference between the amount of exchange received from the amount of exchange delivered.

Step 4: Identify Wheeled (Net)

Total the difference between the amount of energy entering your owned and or operated system for transmission through your system and the amount of energy leaving your system in MWh. Determine the energy losses on your system associated with the wheeling of energy for other systems.

Step 5: Identify Transmission by Others, Losses

Calculate the amount of energy losses in MWh associated with the wheeling of electricity provided to your owned and /or operated system by other utilities. Transmission by Others Losses should always be expressed as a negative value.

Step 6: Identify Total Sources

Calculate the sum of the energy sources (Net Generation, Purchases from Electricity Suppliers, Exchanges (Net), Wheeled (Net), and Transmission by Others, Losses).

Step 7: Identify Retail Sales to Ultimate Customers

Identify the amount of electricity in MWh sold to customers purchasing electricity for their own use and not for resale.

Step 8: Identify Sales for Resale

Determine the amount of electricity in MWh sold for resale purposes. This entry should include sales for resale to power marketers, full and partial requirements (firm) customers and to non-requirements (nonfirm) customers.

Step 9: Identify Energy Furnished Without Charge

Identify the amount of electricity in MWh furnished by the electric utility without charge, such as to a municipality under a franchise agreement or for public street and highway lighting.

Step 10: Identify Energy Consumed Without Charge

Determine the amount of electricity in MWh used by the electric utility in its electric and other departments without charge.

Step 11: Identify Energy Consumed by Facility (Independent Power Producers or Qualifying Facility)

Calculate the amount of electric energy in MWh consumed at the facility in support of a service or manufacturing process.

Step 12: Identify Total Energy Losses

Identify the total amount of electricity lost from transmission, distribution, and/or unaccounted for. This is the difference between total sources, and the sum of Retail Sales to Ultimate Customers + Sales for Resale + Energy Furnished Without Charge + Energy Consumed by Respondent Without Charge + Energy Consumed by Facility (Independent Power Producers or Qualifying Facility). Total Energy Losses should always be expressed as a positive value.

Step 13: Identify T&D Loss Factor

Divide Total Energy Losses by Total Sources to identify the T&D Loss Factor in percentage terms.

Step 14: Identify Portion of Losses Attributable to Purchases and Wheeled Electricity

Multiply the T&D loss Factor by the "Total Purchases from Electricity Suppliers" and "Wheeled Received (In)" to calculate total T&D losses attributable to purchases and wheeled and record these values separately.

8.4.2 Indirect emissions associated with T&D Losses

Calculate indirect emissions associated with these T&D losses using the following six steps:

1. Identify the weighted average GHG emission factor of Power Purchases.
2. Identify the Weighted Average GHG Emission Factor of Wheeled Electricity.
3. Calculate Indirect CO₂ emissions and Convert to metric tons.
4. Calculate Indirect CH₄ emissions and convert to metric tons.
5. Calculate Indirect N₂O emissions and convert to metric tons.
6. Convert GHG emissions to CO₂ equivalents and sum all subtotals.

To calculate your weighted average emission factor, you must first determine the emission factor of each power purchase.

Step 1: Identify the Weighted Average GHG Emission Factors for Power Purchases

To determine a weighted average emissions factor for all electricity purchases, you must first determine the percentage of purchased power derived from each source (spot market, each facility, and each utility) and then multiply that percentage by each source-specific emission factor as illustrated in the equation below.

$$E = (S * S_f) + (F * F_f) + (U * U_f)$$

Where: E=weighted average emissions factor for purchased power

S =proportion of power purchased from the spot market
 S_f =average emission factor for spot purchases (power pool emission factor)
 F =proportion of power purchased from a specific facility (for each facility)
 F_f =facility-specific emission factor (for each facility)
 U =proportion of power purchased from a specific utility (for each utility)
 U_f =utility-specific emission factor (for each utility)
 $S+F+U=1$

For any electricity purchase whose resources are known—i.e., purchased from a utility or a generator, you should use the GHG emission rate associated with that purchase. This can be the default emission factor from eGRID, or obtained directly from the generator.

If your company already tracks this information for compliance with state environmental disclosure rules, you may use this information to quantify the emissions factors associated with those purchases.

For any power purchased from the spot market, you should use the default emission factor.

Step 2: Identify the Weighted Average GHG Emission Factors for Wheeled Electricity

For wheeled electricity, if the particular generation resources are known, you should obtain the GHG emission factor of the power from the generator or utility, if available. If your company already tracks this information for compliance with state environmental disclosure rules, you may use this information to quantify the emissions factors associated with that wheeled electricity. If generator- or utility-specific emission factors are not available, use the default emission factors found in Table 8-2 (eGRID Subregion emission factors).

For all spot market power purchases, use the eGRID Subregion emission factors. For guidance regarding eGRID and emission factors resources, see the section below on emission factors.

To determine a weighted average emissions factor for all wheeled electricity, you must first determine the percentage of wheeled power derived from each source (known and unknown resources) and then multiply that percentage by each source-specific emission factor as illustrated in the equation below.

$$E = (K * K_f) + (U * U_f)$$

Where: W =weighted average emissions factor for wheeled power

K =proportion of power wheeled from known resources

k_f =average emission factor for known resources

U =proportion of power wheeled from a unknown resources

U_f =regional-specific emission factor (power pool emission factor)

$K+U=1$

Step 3: Calculate Indirect CO₂ emissions and Convert to metric tons;

Once you have determined the weighted average CO₂ emission rates for purchased and wheeled power, multiply the MWh losses calculated in Step 2 by the applicable CO₂ emission rates. Sum all CO₂ emissions and convert to metric tons by dividing by 2,204.6.

Equation 8a		Determining Indirect CO ₂ Emissions Associated with Purchased Power		
Total Indirect CO ₂ Emissions from Purchased power (metric tons)	=	Total Losses attributed to Purchases (MWh)	X	Weighted Average Emission Factor of Purchased Power (lbs CO ₂ /MWh) / 2,204.6 lbs/metric ton

While direct access is a portion of your wheeled power, to report to the Registry, you should distinguish the emissions from direct access from the rest of your wheeled power to provide greater transparency. Subtract your direct access from your wheeled power and calculate emissions from direct access separately.

Equation 8b		Determining Indirect CO ₂ Emissions Associated with Wheeled Power		
Total Indirect CO ₂ Emissions from Wheeled Power (metric tons)	=	Total Losses Wheeled Power (MWh)	X	Weighted Average Emission Factor of Wheeled Power (lbs CO ₂ /MWh) / 2,204.6 lbs/metric ton

Equation 8c		Determining Indirect CO ₂ Emissions Associated with Direct Access		
Total Indirect CO ₂ Emissions from Direct Access (metric tons)	=	Total Losses Direct Access (MWh)	X	Weighted Average Emission Factor of Direct Access (lbs CO ₂ /MWh) / 2,204.6 lbs/metric ton

Step 4: Calculate Indirect CH₄ emissions and Convert to metric tons

Once you have determined the CH₄ emission rates, multiply the MWhs purchased and the MWhs wheeled by the applicable CH₄ emission rates. Sum all CH₄ emissions and convert to metric tons by dividing by 2,204.6.

Equation 8d		Determining Indirect CH ₄ Emissions Associated with Purchased Power		
Total Indirect CH ₄ Emissions from Purchased power (metric tons)	=	Total Losses attributed to Purchases (MWh)	X	Weighted Average Emission Factor of Purchased Power (lbs CH ₄ /MWh) / 2,204.6 lbs/metric ton

Subtract your direct access from your wheeled power and calculate emissions from direct access separately.

Equation 8e		Determining Indirect CH ₄ Emissions Associated with Wheeled Power		
Total Indirect CH ₄ Emissions from Wheeled Power (metric tons)	=	Total Losses Wheeled Power (MWh)	X	Weighted Average Emission Factor of Wheeled Power (lbs CH ₄ /MWh) / 2,204.6 lbs/metric ton

Equation 8f Determining Indirect CH ₄ Emissions Associated Direct Access				
Total Indirect CH ₄ Emissions from Direct Access (metric tons)	=	Total Losses Direct Access (MWh)	X Weighted Average Emission Factor of Direct Access (lbs CH ₄ /MWh)	/ 2,204.6 lbs/metric ton

Step 5: Calculate Indirect N₂O emissions and Convert to metric tons

Once you have determined the N₂O emission rates, multiply the MWhs purchased and wheeled power by the applicable N₂O emission rates. Sum all N₂O emissions and convert to metric tons by dividing by 2,204.6.

Equation 8g Determining Indirect N ₂ O Emissions Associated with Purchased Power				
Total Indirect N ₂ O Emissions from Purchased power (metric tons)	=	Total Losses attributed to Purchases (MWh)	X Weighted Average Emission Factor of Purchased Power (lbs N ₂ O/MWh)	/ 2,204.6 lbs/metric ton

Subtract your direct access from your wheeled power and calculate emissions from direct access separately.

Equation 8h Determining Indirect N ₂ O Emissions Associated with Wheeled Power				
Total Indirect N ₂ O Emissions from Wheeled Power (metric tons)	=	Total Losses Wheeled Power (MWh)	X Weighted Average Emission Factor of Wheeled Power (lbs N ₂ O/MWh)	/ 2,204.6 lbs/metric ton

Equation 8i Determining Indirect N ₂ O Emissions Associated with Direct Access				
Total Indirect N ₂ O Emissions from Direct Access (metric tons)	=	Total Losses Direct Access (MWh)	X Weighted Average Emission Factor of Direct Access (lbs N ₂ O/MWh)	/ 2,204.6 lbs/metric ton

Step 6: Convert GHG emissions to CO₂ equivalents and sum all subtotals.

Once you have determined all the GHG emissions, convert the CH₄ and N₂O emissions into carbon equivalents using their global warming potentials (GWPs) and sum all CO₂ emissions.

Equation 8j Converting Mass Estimates to Carbon Dioxide Equivalent			
Metric Tons of CO ₂ e	=	Metric Tons of GHG	x GWP

8.5 Indirect Emissions from Purchased and Wheeled Electricity

To determine your emission factor for your purchased electricity sold to end-users, you must first determine the emissions factor for your entire portfolio of purchased, wheeled power and direct access, or your entity-wide emissions factor. This should be a weighted average of known and unknown resources, including:

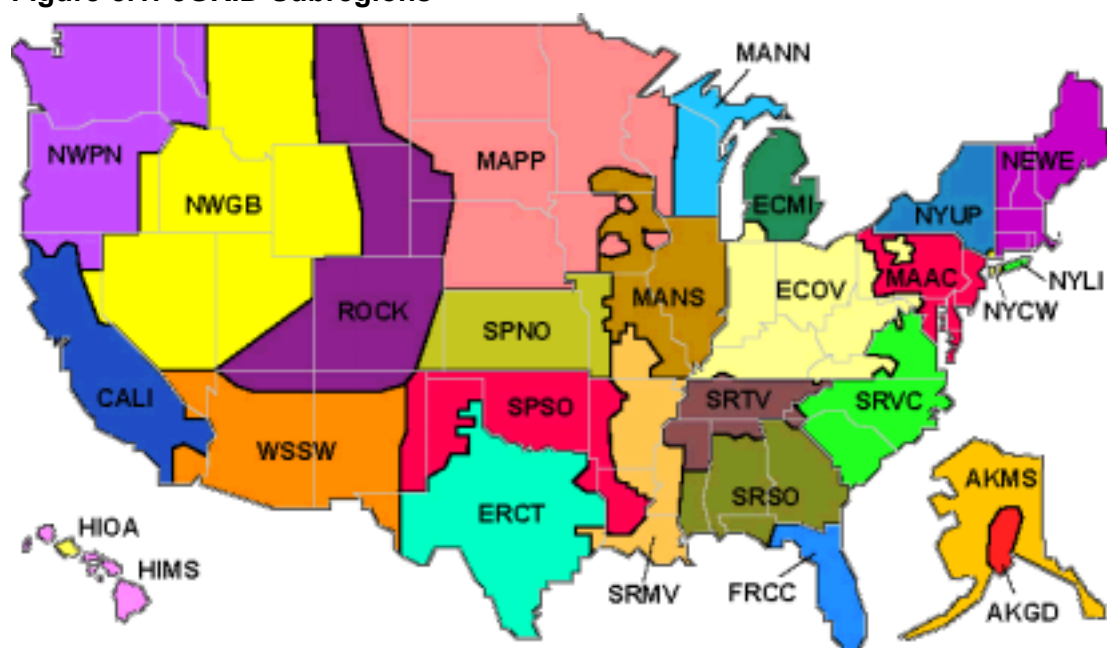
- **Facility-specific purchases:** When power purchase agreements (PPAs) create an agreement between a specific facility and a transmission/distribution company, the purchaser should use a facility-specific emissions factor.

- **Utility-specific purchases:** If you have a PPA with an electric utility that covers a number of facilities, you should use a utility-specific emissions factor
- **Spot market purchases.** Because spot market purchases cannot be traced back to a specific source and therefore do not have a unique or reliable emission factor, you should use the spot market emission factor.

As a first step in calculating your indirect emissions, you will need to know the appropriate emission factor for your purchased and wheeled power. These may come from either source- or supplier-specific emission factors, or average power pool-specific emission factors.

As a default, you may use average power pool numbers, listed in Table 8.2, provided from U.S. EPA's eGRID database.¹³

Figure 8.1: eGRID Subregions



¹³ The Emissions & Generation Resource Integrated Database (eGRID) provides information on the air quality attributes of almost all the electric power generated in the United States. eGRID provides search options including information for individual power plants, generating companies, states, and regions of the power grid. eGRID integrates 24 different federal data sources on power plants and power companies, from three different federal agencies: EPA, the Energy Information Administration (EIA), and the Federal Energy Regulatory Commission (FERC). Emissions data from EPA are carefully integrated with generation data from EIA to produce useful values like pounds per megawatt-hour (lbs/MWh) of emissions, which allows direct comparison of the environmental attributes of electricity generation. eGRID also provides aggregated data to facilitate comparison by company, state, or power grid region. eGRID's data encompass more than 4,700 power plants and nearly 2,000 generating companies. eGRID also documents power flows and industry structural changes. <http://www.epa.gov/cleanenergy/egrid/index.htm>.

Table 8.2 eGRID Subregion Annual Average CO₂ Output Based Emission Rates (Year 2000 – Total Energy)

eGRID Subregion Name	eGRID Subregion Acronym	CO ₂ Output Emission Rate (lbs/MWh)
ASCC Alaska Grid	AKGD	1,399.95
ASCC Miscellaneous	AKMS	757.81
ECAR Michigan	ECMI	1,632.06
ECAR Ohio Valley	ECOV	1,966.53
ERCOT All	ERCT	1,408.27
FRCC All	FRCC	1,390.04
HICC Miscellaneous	HIMS	1,702.93
HICC Oahu	HIOA	1,721.69
MAAC All	MAAC	1,097.56
MAIN North	MANN	1,761.09
MAIN South	MANS	1,237.29
MAPP All	MAPP	1,838.83
NPCC Long Island	NYLI	1,659.76
NPCC New England	NEWE	897.11
NPCC NYC/Westchester	NYCW	1,090.13
NPCC Upstate NY	NYUP	843.04
Off-Grid	OFFG	1,706.71
SERC Mississippi Valley	SRMV	1,331.34
SERC South	SRSO	1,561.51
SERC Tennessee Valley	SRTV	1,372.70
SERC Virginia/Carolina	SRVC	1,164.19
SPP North	SPNO	2,011.15
SPP South	SPSO	1,936.65
WECC California	CALI	804.54
WECC Great Basin	NWGB	852.31
WECC Pacific Northwest	NWPN	671.04
WECC Rockies	ROCK	1,872.51
WECC Southwest	WSSW	1,423.95

eGRID2002 Version 2.01 Location (Operator)-Based eGRID Subregion File (Year 2000 Data)

8.5 Net Metering

If you have a net meter at your facility, you should report any on-site generation as direct stationary combustion. You should calculate your indirect emissions based on the portion of your electricity you purchase from the grid only.

Chapter 9: Industry-Specific Efficiency Metrics

What you will find in Chapter 9	This chapter provides guidance on determining what industry-specific metric(s) you must report to the Registry in addition to entity-wide absolute emissions.
Information you will need	You may need information on your total annual emissions, total purchases and deliveries of electricity and/or natural gas.

9.1 Purpose of Reporting Industry-Specific Metrics

Normalized emissions are your emissions divided by a measure of your output. The specific output measure depends on the nature of the organization that is reporting. Reporting normalized emissions allows trends in the carbon intensity of an activity to be gauged by removing the effects of changing outputs on the results. The common terms for these measures are “efficiency metrics” or “carbon intensity metrics”.

For the purposes of this protocol, there are two main reasons for requiring the reporting of electric power and utility industry-specific metrics:

1. To provide a basis for consistent comparison across the industry regardless of entity size for use by the public and interested stakeholders.
2. To track carbon intensity performance over time and complement the entity-wide absolute emissions reporting.

9.2 Mandatory Efficiency Metrics

For the electric power and utility sectors the following efficiency metrics must be reported:

1. *Energy Output*: Pounds of direct carbon dioxide equivalent emissions per million British Thermal Units of energy output from all entity-owned or -controlled assets and facilities (lbs. $\text{CO}_2\text{e}_{\text{Direct}}/\text{MMBtu}_{\text{Direct}}$);
2. *Electricity Generation*: Pounds of direct carbon dioxide equivalent emissions per net megawatt hour of electricity generated from entity-owned or -controlled electric generating facilities only (lbs $\text{CO}_2\text{e}_{\text{Direct}}/\text{MWh}_{\text{Net Generated}}$);
3. *Fossil Electricity Generation*: Pounds of direct carbon dioxide equivalent emissions per net megawatt hour of electricity generated from entity-owned or -controlled fossil-fuel fired electric generating facilities only (lbs $\text{CO}_2\text{e}_{\text{Direct}}/\text{MWh}_{\text{Net Fossil Generated}}$);
4. *Electricity Deliveries*: Pounds of direct and indirect carbon dioxide equivalent emissions per net electricity generated and net electricity purchased from others for resale to end-users (lbs. $\text{CO}_2\text{e}_{\text{Direct and Indirect}}/\text{MWh}_{\text{Net Generated and Net Purchased}}$); and
5. *Natural Gas Deliveries*: Pounds of direct carbon dioxide equivalent emissions per therm of natural gas delivered from entity-owned or -controlled natural gas transmission, storage and/or distribution assets (lbs. $\text{CO}_2\text{e}_{\text{Direct}}/\text{Therm}$).

Emissions that you have classified as de minimis should not be included in the calculations of your efficiency metrics.

Which efficiency metric you must report depends on the nature of your business operations. At a minimum, you must report at least two metrics from the required list above. More specifically:

- Every entity must report the *energy output* metric.
- If your organization is vertically integrated (you own or control generation, natural gas & electric transmission, and distribution systems) and you have fossil-fired generation, you must report all five metrics.
 - If your organization is vertically integrated (you own or control generation, natural gas & electric transmission, and distribution systems) but you have *no* fossil-fired generation, you must report all metrics except the fossil fuel-fired electricity generation metric.
- If you only own or control electric generation assets and do not purchase power from any other companies or have any natural gas assets, you must report the *energy output* and *electricity generation* metrics.

If you have questions regarding which metrics you are required to report to the Registry, please contact the Registry.

If you are reporting only your California emissions, you should include only the emissions and energy outputs from facilities located in California and/or the portion of emissions and energy outputs from your facilities located outside of California but delivered to your customers in California.

9.3 Calculating Efficiency Metrics

To assist you in reporting these required metrics, the guidance below outlines the necessary steps to quantifying these metrics. For a discussion on optional metrics see Chapter 11 – Optional Reporting.

9.3.1 **Energy Output: Pounds of direct carbon dioxide equivalent emissions per million British Thermal Units of energy output from all entity-owned or controlled assets and facilities (lbs. CO₂e_{Direct}/MMBtu_{Direct})**

All power/utility entities reporting to the Registry must report this entity-wide metric, which incorporates all of your required direct emissions including:

- stationary combustion from the onsite production of heat, steam, or electricity owned or controlled by your organization;
- fugitive leaks or venting from operations owned or controlled by your organization including:
 1. natural gas systems
 2. electricity transmission and/or distribution systems,
 3. air conditioning and refrigeration systems, and
 4. fire suppression equipment;
- processes such as emission control technologies and other activities that are owned or controlled by your organization; and
- mobile combustion from non-fixed sources that are owned or controlled by your organization.

To calculate this entity-wide metric, follow these four steps:

Step 1: Sum all of your entity-wide direct CO₂e emissions. Include all the direct emissions from stationary and mobile combustion, fugitive leaks and venting, and processes.

Step 2: Sum your total natural gas deliveries in therms and convert to million British thermal units (MMBtu) by multiplying by 0.1.¹⁴

Step 3: Sum your net electricity generation in MWhs and convert to MMBtu by multiplying by 3.412.¹⁵

Step 4: Sum total entity-wide MMBtu and divide the direct CO₂e emissions from Step 1 by the entity-wide MMBtu.

Step 5: Convert to lbs. by multiplying by 2,204.6 lbs/metric ton. The equation is illustrated below.

Equation 9a		Entity-wide Carbon Intensity Metric (lbs CO ₂ e _{Direct} /MMBtu)						
Carbon Intensity Metric – Entity-wide (lbs CO ₂ e/MMBtu)	=	Entity-wide Direct CO ₂ e Emissions (metric tons CO ₂ e)	/	Natural Gas Deliveries (MMBtu)	+	Net Electricity Generation (MMBtu)	x	2,204.6 lbs/metric tons

9.3.2 **Electricity Generation: Pounds of direct carbon dioxide equivalent emissions per net megawatt hour of electricity generated from entity-owned or controlled electric generating facilities only (lbs CO₂e_{Direct}/MWh_{Net Generated})**

If you own or control electric generating facilities report your pounds of carbon dioxide equivalent (CO₂e) emitted onsite to generate electricity per net megawatt hour generated on a total energy basis (including fossil fuel, non-emitting resources such as renewable energy and nuclear power).

To calculate this metric, follow these four steps:

Step 1: Sum all of your CO₂e emissions from stationary fossil fuel combustion activities associated with the generation of electricity at entity-owned or -controlled electric generation facilities.

Step 2: Sum all of the net electricity generation associated with entity-owned or -controlled electric generation in MWh, and

Step 3: Divide the CO₂e emissions from Step 1 by the net electricity generation from Step 2.

Step 4: Convert to lbs. by multiplying by 2,204.6 lbs/metric ton.

Equation 9b		Carbon Intensity of Electricity Generation (lbs CO ₂ e _{Direct} /MWh _{Net Generated})				
Carbon Intensity Metric - Generation (lbs CO ₂ e/MWh _{Net Generated})	=	Direct CO ₂ e Emissions Associated with Electricity Generation (metric tons CO ₂ e)	/	Entity-wide Electricity Generation (MWh _{Net})	x	2,204.6 lbs/metric tons

9.3.3 **Fossil Electricity Generation: Pounds of direct carbon dioxide equivalent emissions per net megawatt hour of electricity generated from entity-owned or -controlled fossil-fuel fired electric generating facilities only (lbs CO₂e_{Direct}/MWh_{Net Fossil Generated});**

¹⁴ Therm to MMBtu conversion source – Energy Information Administration (EIA), *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996), Appendix B.

¹⁵ MWh to MMBtu conversion source – Same as above.

If you own or control fossil fuel-fired electric generating facilities, report your pounds of carbon dioxide equivalent (CO₂e) emitted onsite to generate electricity per net megawatt hour generated of fossil fuel-fired generation, (including coal, oil, natural gas, and diesel). The metric should be reported as lbs. CO₂e/MWh.

To calculate this metric, follow these four steps:

Step 1: Sum all of your CO₂e emissions from stationary fossil fuel combustion activities associated with the generation of electricity at entity-owned or -controlled electric generation facilities.

Step 2: Sum all of the net electricity generation associated with entity-owned or -controlled fossil fuel-fired electric generation in MWh, and

Step 3: Divide the CO₂e emissions from Step 1 by the net fossil fuel-fired electricity generation from Step 2.

Step 4: Convert to lbs. by multiplying by 2,204.6 lbs/metric ton.

Equation 9b		Carbon Intensity of Fossil Electricity Generation (lbs CO ₂ e _{Direct} /MWh _{Net Generated})	
Carbon Intensity Metric - Generation (lbs CO ₂ e/MWh _{Net Fossil Generation})	Direct CO ₂ e Emissions	Entity-wide Fossil Electricity Generation	x 2,204.6 lbs/metric tons
	= Associated with	/	
	Fossil Electricity Generation (metric tons CO ₂ e)	(MWh _{Net Fossil Generation})	

9.3.4 **Electricity Deliveries: Pounds of direct and indirect carbon dioxide equivalent emissions per net electricity generated and net electricity purchased from others for resale to end-users (lbs. CO₂e_{Direct and Indirect} /MWh_{Net Generated and Net Purchased})**

If you own or control electric generation and also purchase electricity for resale to end-users, report your lbs CO₂e/MWh on a total energy basis including both net generated and net purchased power.

To calculate this metric, following the following five steps:

Step 1: Sum all of your direct CO₂e emissions from stationary fossil fuel combustion activities associated with the generation of electricity at entity-owned or -controlled electric generation facilities.

Step 2: Sum all of your indirect CO₂e emissions associated with stationary fossil fuel combustion activities at electric generation facilities from which you purchase power.

Step 3: Sum your entity-wide net electricity generation and net purchased power (for delivery to end-users) in MWhs.

Step 4: Divide the CO₂e emissions from the sum of Step 1 and Step 2 by the net electricity generation from Step 3.

Step 5: Convert to lbs. by multiplying by 2,204.6 lbs/metric ton. The equation is illustrated below.

Equation 9c		Carbon Intensity of Net Electricity Generation and Net Electricity Purchases (lbs CO ₂ e _{Direct} and Indirect/MWh _{Net} Generated and Net Purchased)				
Carbon Intensity Metric – Generation and Purchases (lbs CO ₂ e/MWh _{Net} Generated and Net Purchased)	=	Direct CO ₂ e Emissions Associated with Net Electricity Generation (metric tons CO ₂ e)	+	Indirect CO ₂ e Emissions Associated with Net Purchased Electricity (metric tons CO ₂ e)	/	Entity-wide Net Electricity Generation (MWh _{net})
					+	Net Purchased Electricity for Resale to End-users (MWh _{net})
						x 2,204.6 lbs/metric tons

9.3.5 Natural Gas Deliveries: Pounds of direct carbon dioxide equivalent emissions per Therm of natural gas delivered from entity-owned or controlled natural gas transmission, storage and/or distribution assets (lbs. CO₂e_{Direct}/Therm)

If you own or control natural gas transmission, storage and/or distribution assets you shall report lbs. CO₂e/therm of natural gas delivered to end-users.¹⁶

To calculate this metric, follow these four steps:

Step 1: Sum all of your direct CO₂e emissions from your natural gas transmission, storage, and/or distribution system. Include all the direct emissions associated with the physical natural gas system you own or control including: stationary combustion activities, fugitive emissions of methane (CH₄) and CO₂, and vented emissions.

Step 2: Sum your total natural gas deliveries to end-users in therms.

Step 3: Divide the CO₂e emissions from Step 1 by the therms of natural gas deliveries to end-users from Step 2.

Step 4: Convert to lbs. by multiplying by 2,204.6 lbs/metric ton. The equation is illustrated below.

Equation 9d		Carbon Intensity of Natural Gas Delivery (lbs CO ₂ e _{Direct} /Therm)		
Carbon Intensity Metric – Natural Gas (lbs CO ₂ e/Therm)	=	Direct CO ₂ e Emissions Associated with Natural Gas System (metric tons CO ₂ e)	/	Natural Gas Deliveries to End Use Customers (Therm)
				x 2,204.6 lbs/metric tons

9.4 Efficiency Metrics and Combined Heat and Power

Accounting for the GHG emissions from combined heat and power (CHP) is unique in the power/utility sectors because it produces more than one useful product from the same amount of fuel combusted, namely, electricity and heat or steam. As such, apportionment of the fuel and the GHG emissions between the two different energy streams is necessary. Most CHP systems capture the waste-heat from the primary electricity generating pathway and use it for climate control purposes, or to produce steam for other objectives. When the waste-heat is used directly to drive a thermal generator or to make steam that in turn drives an electric generator, these combined electricity production processes are grouped as a unit and called a combined cycle power plant. (The Registry treats emissions resulting from combined cycle power plants

¹⁶ A therm is 100,000 Btus and is the unit most often used by distribution companies. One decatherm (Dth) is 10 therms, or one MMBtu (one million Btu).

as stationary combustion emissions.) The steps below show how to distinguish emissions associated with power generation from other processes that use the waste-heat from electricity production.

The three most commonly-used methods to allocate emissions of CHP plants between the electric and thermal outputs are:

1. *Efficiency method*: On the basis of the energy input used to produce the separate steam and electricity products.
2. *Energy content method*: On the basis of the energy content of the output steam and electricity products.
3. *Work potential method*: On the basis of the exergy content of the steam and electricity products.

Table 9.1 Considerations in Selecting an Approach to CHP Emissions Allocation

Efficiency Method	<ul style="list-style-type: none"> Allocates emissions according to the amount of fuel energy used to produce each final energy stream. Assumes that conversion of fuel energy to steam energy is more efficient than converting fuel to electricity. Thus, focuses on the initial fuel-to-steam conversion process. Actual efficiencies of heat and of power production will not be fully characterized, necessitating the use of assumed values.
Energy Content Method	<ul style="list-style-type: none"> Allocates emissions according to the useful energy contained in each CHP output stream Need information regarding the intended use of the heat energy. Best suited where heat can be characterized as useful energy, e.g., for process or district heating. May not be appropriate where heat used for mechanical work because it may overstate the amount of useful energy in the heat, resulting in a low emissions factor associated with the heat stream.
Work Potential Method	<ul style="list-style-type: none"> Allocates emissions based on the useful energy represented by electric power and heat, and defines useful energy on the ability of heat to perform work. Appropriate when heat is to be used for producing mechanical work (where much of the heat energy will not be characterized as useful energy). May not be appropriate for systems that sell hot water because hot water cannot be used, as steam can, to perform mechanical work.

In order to insure a consistent approach in the power/utility sector to allocating GHG emissions in CHP applications, the Registry recommends the use of the **efficiency method**. A default quantification methodology is provided below for this method. For more information on alternative CHP methods, see the GRP and the GHG Protocol.¹⁷

9.5 Efficiency Method

For this method, emissions are allocated based on the separate efficiencies of steam and electricity production. Use the following steps to determine the share of CO₂ emissions attributable to steam and electricity production:

¹⁷ WRI/WBCSD GHG Protocol Corporate Accounting and Reporting Standard (Revised Edition).

Step 1: Determine the total direct emissions and the total steam and electricity output for the CHP system.

Calculate total direct GHG emissions using Equation 9e below.

Steam tables provide energy content (enthalpy) values for steam at different temperature and pressure conditions. Enthalpy values multiplied by the quantity of steam give energy output values. Obtain the steam energy content values from the IAPWS-IF97 steam tables.¹⁸

To convert electricity output to MMBtu, sum your net electricity generation in MWhs and multiply that value by 3.415.¹⁹

Equation 9e			
Total CO ₂ Emissions (Fuel Consumption is in MMBtu)			
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CO ₂ /MMBtu)	\times Fuel Consumed (MMBtu) \times 0.001 metric tons/kg

Combine the steam and electricity outputs into one energy output value, expressed in the same units of energy (MMBtu) using Equation 9f below.

Equation 9f	
Total Energy Output (in MMBtu)	
Total Energy Output (MMBtu)	= Steam Output (MMBtu) + Electricity Output (MMBtu)

Step 2: Determine the efficiencies of steam and electricity production.

Identify steam efficiencies. If actual efficiencies are not known, use default values of 80% for steam. Identify electricity efficiencies. If actual efficiencies are not known, use default value of 35% for electricity.

Step 3: Determine the fraction of total emissions to allocate to steam and electricity production.

Calculate the portion of your total emissions associated with steam using the following formulas:

$$E_H = \frac{H e_H}{H e_H + P e_P} * E_T \quad \text{and} \quad E_P = E_T - E_H$$

where:

E_H	=	emissions allocated to steam production
H	=	steam output (energy)
e_H	=	assumed efficiency of steam production
P	=	delivered electricity generation (energy)
e_P	=	assumed efficiency of electricity generation
E_T	=	total direct emissions of the CHP system
E_P	=	emissions allocated to electricity production

Note: The use of default efficiency values may, in some cases, violate the energy balance

¹⁸ IAPWS Industrial Formulation 1997 for the Thermodynamic Properties of Water and Steam (IAPWS-IF97), International Association for the Properties of Water and Steam. This publication replaces the previous industrial formulation, IFC-67.

¹⁹ MWh to MMBtu conversion source – Energy Information Administration (EIA), *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996), Appendix B.

constraints of some CHP systems. However, total emissions will still be allocated between the energy outputs. Nevertheless, you should be aware of the energy balance. If the constraints are not satisfied e_H and e_P can be modified until constraints are met.

Step 4: Calculate emission rates for steam and electricity production.

Divide the total CO₂ emissions from steam production (Step 3) by the total amount of steam produced to get an emission rate of pounds of carbon dioxide equivalents per thousand pounds of steam produced (lbs CO₂e/Mlbs of steam).

Equation 9g	Emission Rate for Steam Production (lbs CO ₂ e/Mlbs of steam)			
Emission Rate for Steam Production (lbs CO₂e/Mlbs of steam)	=	Total CO ₂ e Emissions from Steam Production (metric tons CO ₂ e)	/	Total Quantity of Steam Produced (Mlbs of steam) × 2,204.6 lbs CO ₂ e/metric ton

Divide the total CO₂ emissions from electricity production (Step 3) by the total amount of electricity produced to get an emission rate of pounds of carbon dioxide equivalents per megawatt hour generated (lbs CO₂e/MWh).

Equation 9h	Emission Rate for Electricity Production (lbs CO ₂ e/MWh)			
Emission Rate for Electricity Production (lbs CO₂e/MWh)	=	Total CO ₂ e Emissions from Electricity Production (metric tons CO ₂ e)	/	Total Quantity of Electricity Produced (MWh) × 2,204.6 lbs CO ₂ e/metric ton

Step 5: Estimate CO₂ emissions from purchases or sales.

To estimate emissions, multiply the amount of steam or electricity either purchased or sold by the appropriate emission rate (Step 4). Note: units used to report steam or electricity should be the same units as used to calculate the emission rates.

Equation 9i	Total CO ₂ Emissions (Fuel Consumption is in MMBtu)			
Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CO ₂ /MMBtu)	×	Fuel Consumed (MMBtu) × 0.001 metric tons/kg

Chapter 10: Calculating De Minimis Emissions

What you will find in Chapter 10	This chapter provides guidance on estimating emissions that may be <i>de minimis</i> in quantity.
Information you will need	You may need information on your total annual emissions, total purchases and deliveries of electricity and/or natural gas.

For many power/utility entities the administrative effort associated with identifying, quantifying, and reporting all of their GHG emissions could be unduly burdensome and not cost-effective.

You must report at least 95% of your total emissions. To reduce the reporting burden, each participant can declare up to 5% of their total emissions as *de minimis*. *De minimis* emissions must be estimated and reviewed by the certifier, but do not need to be publicly reported.

While the sources and gases that will be *de minimis* will vary from participant to participant, your estimates must be conservative, verifiable, and appropriately documented. You should estimate *de minimis* emissions using conservative “rough upper bounds” estimates (since the amounts may be insignificant even as upper bounds). Your estimations and assumptions in calculating your *de minimis* emissions will need to be provided to and reviewed by your certifier. If your operations do not change significantly from year to year, you will only need to re-calculate and have reviewed your *de minimis* emissions every three years. Also, for certification purposes, records and documentation that support the *de minimis* calculations should be made available to the certifier.

10.1 Calculating De Minimis Emissions

The following calculations provide acceptable conservative methods for illustrating *de minimis* emissions for power/utility entities. These examples assume an entity that has entity-wide emissions of 3 million tons of CO₂e which means that it can identify a mix of sources as *de minimis* up to a total of 150,000 tons of CO₂e.

10.1.1 Stationary Combustion Sources

In certain circumstances, power/utility entities may not have the necessary fuel use data for small combustion sources to estimate emissions according to the PUP. Where limited data exists for small combustion sources, conservative engineering estimates are an acceptable method for quantifying GHG emissions and illustrating whether these emissions are *de minimis*.

Estimate your direct CO₂ emissions from stationary combustion sources using the following process:

1. Identify the operating parameters of the source;
2. Identify the appropriate emission factor based on fuels combusted in the source; and
3. Calculate CO₂ emissions and convert to metric tons;

Each of these steps is described in greater detail below.

Step 1: Identify the Operating Parameters of the Source

Use company records to identify the capacity of the piece of equipment along with conservative assumptions about operating hours and fuel use to calculate emissions.

Step 2: Identify the Appropriate Emission Factor Based on Fuel Combusted in the

Source

Use the default emission factors provided in Chapter 5 (Stationary Combustion) to calculate CO₂ emissions associated with the source.

Step 3: Calculate CO₂ Emissions and Convert to Metric Tons

Use the default emission factors identified to calculate CO₂ emissions associated with the source and divide the number of lbs CO₂ obtained by 2,204.6 lbs/metric ton to obtain metric tons of CO₂ produced.

Example 1:

Company A has an oil-fired auxiliary boiler (Boiler X) with a nameplate capacity of 2 mmBtu/hr. The boiler has no fuel meter. The boiler is used only for plant startups and quarterly operational checks.

Estimate the emissions from Boiler X:

In a typical year no more than two or three plant startups occur. Quarterly checks and startups are assumed to last for five hours with Boiler X operating at full capacity. To achieve a conservative estimate of emissions from Boiler X, assume five plant startups and four quarterly operational checks for a total of nine operating times.

Emissions from Boiler X:

(9 operations x 5 hrs each x 2 mmBtu/hr x 78.79 kg CO₂/mmBtu x 0.001 metric tons/kg = 7.0911 metric tons CO₂

10.1.2 Fugitive CH₄ Emissions from Fuel Handling and Storage

Handling and storage of some fuels may be a source of fugitive CH₄ emissions. For instance, different types of coals desorb methane at different rates, but since coal is usually removed from a mine within hours or days of being mined, some methane remains and is liberated from the coal during handling operations. Fugitive emissions such as these are likely *de minimis* for most entities.

At this time, there is no guidance provided in the PUP to complete a *de minimis* calculation for fugitive emissions from biomass fuel use and handling. However, in the future a method may be identified based on guidance from the CA Registry Forestry Protocol.

A methodology is presented below to help you conservatively estimate fugitive CH₄ emissions associated with coal handling and storage. This method uses U.S. EPA-established emission factors for coals that encompass all post-mining activities, including storage in piles at the utilities.

Estimate your fugitive CH₄ emissions using the following process:

1. Identify the Total Tons of Coal Purchased.
2. Identify the Appropriate Emission Factor Based on Coal Origin.
3. Calculate Fugitive CH₄ emissions and Convert to metric tons.
4. Convert CH₄ emissions to CO₂ equivalents and sum all subtotals.

Each of these steps is described in greater detail below.

Step 1: Identify the Total Tons of Coal Purchased

Consult purchase records to identify the total quantity of coal purchases that originate from underground and surface mines.

Step 2: Identify the Appropriate Emission Factor Based on Coal Origin

Use the default emission factors noted in Table 10.1 below to calculate fugitive methane emissions associated with the fuel handling and storage of the coal.

**Table 10.1: Weighted Average Post Mining
Fugitive CH₄ Emission Factors for Coal**

Coal Mine Type	Emission Factor (scf CH ₄ /ton)
Underground	44.3
Surface	4.8

Step 3: Calculate Fugitive CH₄ Emissions and Convert to Metric Tons

Convert from standard cubic feet of methane to lbs of methane by multiplying by 42.28 lbs CH₄ per thousand standard cubic feet of methane. Divide the number of lbs CH₄ obtained by 2,204.6 lbs/metric ton to obtain metric tons of CH₄ produced.

Equation 10a	Determining Total Annual Fugitive Methane Emissions			
Total Fugitive Emissions of CH ₄ (metric tons)	=	Fugitive Methane Emissions (scf)	X lbs CH ₄ /Mscf	/ 2,204.6 lbs/metric ton

Step 4: Convert CH₄ Emissions to CO₂ Equivalents and Sum all Subtotals

To incorporate and evaluate non-CO₂ gases in your GHG emissions inventory, the mass estimates of these gases will need to be converted to CO₂ equivalent. To do this, multiply the emissions in units of mass by CH₄'s GWP. If non-CO₂ gases are de minimis when converted to CO₂e, you do not need to report them to the Registry. Also, you are not required to report non-CO₂ gases until the fourth year that you report emissions to the Registry.

Equation 10b	Converting Mass Estimates to Carbon Dioxide Equivalent		
Metric Tons of CO ₂ e	=	Metric Tons of GHG	x GWP

Example 2:

In a typical year, Company A purchases 1 million tons of coal.

To achieve a conservative estimate of fugitive emissions from coal purchases, Company A assumes that all the coal originates from underground mines.

Therefore, fugitive emissions from coal=

1 million tons x 44.3 scf CH₄ * (tons) convert to metric tons = 17,841 metric tons CO₂

Chapter 11: Optional Reporting

What you will find in Chapter 11	This chapter provides guidance on reporting additional information on specific activities to reduce your total emissions footprint.
Information you will need	You may need information on your total annual emissions, total purchases and deliveries of electricity and/or natural gas.

In order to certify an emissions report with the California Climate Action Registry program, some categories of emissions are required. These include emissions from direct sources: stationary combustion, mobile combustion, fugitive emissions, process emissions. These also include indirect emissions associated with electricity, steam, heating and cooling that is purchased and consumed. For purposes of this program, *all other categories of information are considered optional. Because there are no protocols governing optional reporting, the optional reporting information is not eligible for certification within the CA Registry. The State of California will only back certified information reported to the CA Registry.*

The Registry encourages its participants to provide additional information, e.g., emissions associated with product shipping, employee commuting and business travel, etc. You may also want to include references to your organization's environmental goals, policies, programs and performance. This information can showcase your environmental efforts, including emission reduction projects. Also, you can provide links to external sources to allow viewers to learn more about your environmental programs. This optional reporting section allows power/utility entities to create a public record of other activities that may complement the emissions inventory.

This chapter outlines some general guidance for optional reporting areas relevant to electric power generators and electric utilities. If you choose to report any of the following activities, you should follow the guidance below.

11.1 Other Reporting

Other activities that you may choose to report include:

- **Indirect emissions from extraction, production, and transportation of fuels used for generation of electricity, heat, or steam.** This includes the upstream emissions associated with the extraction and production of fuels used to generate electricity. Examples include emissions from mining of coal, and extraction of natural gas.
- **Purchases and sales of tradable renewable certificates (TRC).** At a minimum, you should report the quantity of TRCs purchased or sold in a given year, the purpose(s) of the purchase and sales, and the geographic origin of the TRCs. You should also identify the other registries and/or regulatory agencies to which you have reported this information.
- **Annual energy efficiency savings.** You should report megawatts of peak load saved and total electricity saved annually in megawatt-hours. You should also report the reason for undertaking the energy efficiency programs (regulatory requirements, demand response, voluntary, etc), and to which other registries and/or regulatory agencies you have reported this information.
- **Purchases and sales of GHG emission offset projects.** At a minimum, you should report the type of project(s) and the quantity of emission reductions. You should also report the terms of the purchase and/or sale and to which other registries and/or regulatory agencies you have reported this information.

- **Contractual agreements assigning liability.** You should report the details of the specific contractual agreements including: the parties involved, the scope of the agreement, and the duration of the agreement. You should also report to which other registries and/or regulatory agencies you have reported this information.

11.2 Optional Metrics

You may also report optional efficiency metrics as part of your Annual GHG Emission Report to the Registry to highlight aspects of your environmental performance. The following efficiency metrics may be reported along with entity-wide emissions.

- *Fuel- or Facility:* If you own or control electric generating facilities you may report pounds of carbon dioxide equivalent per megawatt hour generated (lbs CO₂e/MWh) on a fuel-specific basis or facility-specific basis.
- *Electricity by Customer Type:* If you own or control electric transmission & distribution assets you may report lbs CO₂e/customer by customer type (residential, commercial, industrial).
- *Natural Gas by Customer Type:* If you own or control natural gas transmission & distribution assets you may report lbs CO₂e/customer by customer type (residential, commercial, industrial).

If your organization is vertically integrated (you own or control generation, transmission, and distribution systems) such as in investor owned utilities, then you may report any combination of the three metrics as outlined above.

Congratulations! Once you have completed calculating the emissions, according to the guidance in this appendix, return to the General Reporting Protocol for information on completing your report, using CARROT, and beginning certification.

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Appendix A:
EPA SF₆ Emissions Reduction Partnership for Electric Power Systems
Change in Inventory (SF₆ contained in cylinders, not electrical equipment)

Inventory (in cylinders, not equipment)	AMOUNT (lbs.)	Comments
1. Beginning of Year		
2. End of Year		
A. Change in Inventory (1 - 2)	-	

Purchases/Acquisitions of SF₆

	AMOUNT (lbs.)	Comments
3. SF ₆ purchased from producers or distributors in cylinders		
4. SF ₆ provided by equipment manufacturers with/inside equipment		
5. SF ₆ returned to the site after off-site recycling		
B. Total Purchases/Acquisitions (3+4+5)	-	

Sales/Disbursements of SF₆

	AMOUNT (lbs.)	Comments
6. Sales of SF ₆ to other entities, including gas left in equipment that is sold		
7. Returns of SF ₆ to supplier		
8. SF ₆ sent to destruction facilities		
9. SF ₆ sent off-site for recycling		
C. Total Sales/Disbursements (6+7+8+9)	-	

Change in Nameplate Capacity

	AMOUNT (lbs.)	Comments
10. Total nameplate capacity (proper full charge) of <u>new</u> equipment		
11. Total nameplate capacity (proper full charge) of <u>retired</u> or <u>sold</u> equipment		
D. Change in Capacity (10 - 11)	-	

Total Annual Emissions

	lbs. SF ₆	Tonnes CO ₂ equiv. (lbs.SF ₆ ×23,900/2205)
E. Total Emissions (A+B-C-D)	-	-

Emission Rate (optional)

	AMOUNT (lbs.)	Comments
Total Nameplate Capacity at End of Year		
	PERCENT (%)	
F. Emission Rate (Emissions/Capacity)		

